

The Economic and System Impacts of increased DG Connection within New Zealand's Electricity Networks

**The New Zealand
Centre for Advanced Engineering**

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1 INTRODUCTION

Previous studies by CAENZ have clearly enunciated the opportunities for Distributed Generation (DG) in New Zealand [12]. The technology has emerged both as a potentially attractive means of providing new electricity generation and as an alternative to expanding the capacity (and/or enhancing security) of established transmission and distribution networks.

The attractiveness of DG has risen because of the ongoing improvement in the enabling technologies, the changing structure of the electricity industry, and government encouragement of renewable energy and “community” energy solutions.

At the same time, continued conventional development of large scale core grid connected generation with its associated transmission reinforcement is becoming more challenging from the perspective of finding suitable routes, consenting of large-scale installations, and achieving optimal investment patterns. It is also becoming increasingly accepted that the creation of an economically efficient and sustainable development path for electricity supply will require modernisation of the total system with solutions that will have a significant component of DG.

A further factor that has acted to enhance the uptake of DG is that failure at a national level to ensure the necessary investments to support the current centralised delivery model. This has led to incremental investments in new generation capacity, reduced reserves margins and increasing pressure on the electricity network reliability and adequacy. Within this environment DG solutions offer shorter construction lead times, easier access to resources, reduced financial risk and hence improved investor appetite and willingness to invest.

Transition from a system that is currently dependent on centralised generation, and its customised supporting transmission grid to deliver system level performance requirements, to one that has devolved some of that function

to distributed generation, is a large hurdle to overcome. Sufficient DG investment is required before it can collectively assume some of functions, such as security, from the larger generation facilities. Thus, while in some respects complimentary, DG can be seen as a competitor to centralised generation and transmission. Broadening the investment opportunity to other sectors of the industry is being matched by more DG being installed.

Undoubtedly from an economic perspective the use of DG prime facia has definite attractions. However barriers do exist. The business environment for the uptake of DG is strongly influenced at present by the uncertainty around the market frameworks in New Zealand. Complexity, technical requirements, levels of service, retail and connection contracts all contribute to investor perception of risk.

An issue has been the apparent inconsistencies between network companies in their treatment of DG investment and the value ascribed to the DG asset in terms of network security and reliability. There are also disparities in the ways in which transmission charges are passed through to end customers through the network operators by way of the retailer's retail tariffs.

From a national perspective it is essential that network companies have a good knowledge and understanding of the motivations that attract DG investment. DG solutions can overcome traditional transmission and distribution lines problems especially where demand diversity and peak load profiles are a significant management issues. However, it cannot be assumed that every distribution network faces these problems. Through historical investment decisions, demographic changes, economic growth (or decline) and a range of other compounding issues individual network companies will have different motivations and drivers in respect of their total asset management strategies.

It is these strategies that ultimately determine how network owners will respond to the challenges of DG integration within their

network business. Understanding these factors is critical to the successful uptake of DG. For these reasons CAENZ has sought in this study to examine the commercial uptake of DG within the current regulated environment and establish some of the factors that lead to successful DG investment.

The study itself looks at a number of case

studies and addresses the features of the different DG alternatives and how these integrate within existing networks. By offering a common framework for addressing the technical and commercial issues around increased DG penetration it is hoped that a more strategic and integrated approach to developing local DG opportunities will ensue.

2 SCOPE OF THE CURRENT STUDY

In this study CAENZ has adopted a framework approach to facilitate its assessment of the network and system benefits of DG uptake. This is intended to deliver a more strategic and integrated approach to assessing energy investments in developing local DG applications.

The project, thus, examined a number of selected network opportunities from the perspective of the DG project sponsor and through discussion with the incumbent network operator assessed the perceived network benefits and potential for further deployment of other opportunities within the selected network area.

A generic framework for characterising the different factors and their application at the distribution level was established as set out below:

Commercial Characteristics

- Investment Criteria (DCF, Hurdle Rate, Time Frame)
- Lines Companies business model
- DG Investor objectives
- Market Issues

Applications

- Intermittent
- Cogeneration
- Standby

System Performance

- Transmission and Distribution
- Diversity

- Adequacy and Security

Regional Development

- Local authority and consumer priorities
- Network Issues
- Access and consenting

Regulatory Environment

- Government policy and support schemes
- Regulation of Lines Companies
- DG Regulations

Operating Experience

- Pricing
- Network benefits

It was not possible to apply all these criteria to each of the cases studies, however, in general sufficient information was able to be gathered to allow the appraisal of the different approaches used to overcome the technical challenges as well as the various connection and commercial issues likely to affect economic performance. In addition the effectiveness of current policy instruments to facilitate DG uptake have been examined and comparisons made with the realities encountered by the generator owner.

The analysis undertaken involved a staged process and considered up to three sites in each network studied to avoid stretching limited resources. To this end for each network company involved, consultation was required within the network company, associated energy generators and the commercial and industrial users.

3 DG CHARACTERISTICS & SYSTEM PERFORMANCE

A definition of DG

The Electricity Governance (Connection of Distributed Generation) Regulations 2007 [3] define distributed generation as equipment used or proposed to be used for generating electricity that is:

- connected or proposed to be connected to a distribution network, or to a consumer installation that is connected to a distribution network; and
- is capable of injecting electricity into that distribution network.

In this study we adhere to this definition, including cogeneration equipment (even if not actually injecting energy into the network, but capable of) and the use of backup-generators for peak lopping (including generation not synchronised and connected to the system).

Distributed generation can transverse a range of applications: from smaller scale power stations (including wind, landfill gas, biomass and small hydro), cogeneration or combined heat and power plants, small stand-alone diesel generators and domestic or small commercial photovoltaic solar generation.

The study assumes three Modes of DG Operation:

- **Mode 1** is the standby generator designed for security of supply (eg for computer installations or hotels) or for peak lopping, which may operate less than 100 hours per year. Firming generation may operate for 500 hours per year. In standby DG we include both generators that are synchronised with the grid as well as those which are not but once the load is temporarily disconnected from the network they start up.
- **Mode 2** is that which is dependent on an intermittent or inexact fuel supply (eg run of river or limited storage hydro, photovoltaics with limited battery storage or wind generators), this is semi base load, in that it runs as much as it's fuel supply allows. This generation may also be

operated to optimise against other generation and/or locational/timing effects on pricing e.g. running a hydro scheme with storage for 4 hours/day at peak times when spot price is highest. Use of gas (for say firming wind generation) may be viable only during the 8 hour daytime base load period.

- **Mode 3** is base load generation which to be economic is usually of the CHP variety (eg Industrial co-generation or a domestic Stirling engine arrangement) or runs on a supply of free fuel, such as methane extracted from a landfill site or sewerage pipes or coal seams. This generation may still not be run during off-peak periods if pricing conditions are below its economic threshold.

We also assume four distinct DG Size Bands, with each having its particular barriers and issues. The 2007 Regulations distinguish two DG size bands (10kW and below, and above 10kW). The second band encompasses the bands 2 to 4 below, but with different timeframes for consideration and prescribed fees.

- **Band 1** is below 10kW which is typical for households and includes PV's, small engine gen-sets, micro CHP and small wind mill battery chargers or pumps. Usually these systems use an inverter to interconnect.
- **Band 2** is between 10kW and 1 MW. This includes commercial standby generation usually diesel or gas engines or small gas turbines as well as some mini-hydro schemes.
- **Band 3** is 1 to 5MW which is where line companies might invest, or have an interest in generation. Diesels, mobile gas turbines, and small hydro are likely contenders here. Waste methane fuelled gas engines used at landfills or sewerage works are also typically in this range.
- **Band 4** is 5MW or above, which typically covers line investment in new renewables (wind or geothermal or hydro) plus industrial cogeneration. Lines companies

currently are required under the Electricity Industry Reform Act 1998 [4] to have a separate company to undertake investment above 5MW in total. (Under current legislation lines companies can only sell the output of generation plant – exemptions are listed in Section 5(2) of the Act.)

Potential Impacts of DG on Networks

There is a significant literature on the likely impacts from the operation of a distribution system with a large amount of distributed generation¹. Typically these can be described as:

- Voltage profiles change along the network, depending on the power produced and the consumption levels, leading to a behaviour different from the typical one
- Voltage transients will appear as a result of connection and disconnecting of generators or even as a result of their operation
- Short-circuit levels increase
- Losses change as a function of the production and load levels
- Congestion in system branches is a function of the production and load levels
- Power quality and reliability may be affected
- Utility protection needs to be coordinated with the schemes installed on the generator's side.

DG spans a wide range of technologies, sizes and fuels. The potential impacts on the network can thus vary accordingly and because of the complexity of the factors involved it is difficult to generalise as to these effects. Resolving these issues typically resides with the network company or system operator. In

this report, therefore, it is not intended to cover these issues in detail, but there are a number of important factors that characterise system operation that are generally not well understood by people from outside the industry who may be contemplating DG investments.

The following commentary sets out in a general sense the range of issues that might arise with increasing DG uptake. These issues are well understood by the industry and standard solutions are available.

Configuration of the Network

Traditionally distribution networks have consisted entirely of passive elements arranged in a tapered radial configuration. Electricity is injected into a network at one point only (the GXP) and the network is generally designed on the basis that power will flow in one direction only, away from the GXP and towards the load.

The magnitude of power flow in any part of the network is determined almost entirely by the nature of the connected load. The required capacity of any element in the network is determined by the maximum connected load, after making appropriate allowances for additional capacity in order to provide the required level of reliability under contingency operating conditions. If the distributed generator absorbs rather than exports reactive energy, the network may also need to supply reactive power.

In a network containing DG, there will be multiple points of injection. Further, at any time, the power injected into the network at any particular injection point is unpredictable since DG is not subject to centralised dispatch. Indeed, the power injection will increasingly be determined by the availability of the primary energy source, which in many instances are from uncontrolled renewable energy sources such as wind speed, water flow or sunlight, or from fluctuating industrial production.

Some DG can be dispatched by the distribution network operator or operated to an agreed set of criteria. Such generation may be being applied to management of transmission cost for example. DG has many more potential applications (and revenue streams) than just

¹ Technical issues are those that relate to the physical connection of the generation plant and resulting effect it has on the distribution network. Issues include network congestion, voltage support, protection control and fault levels, capacity constraints, noise, harmonics and power quality, operational safety and control, access for metering and network stability. Many of the connection issues must be analysed through system studies and modelling. This process requires time and specialist skills. Each proposed generation connection has individual characteristics and each must be treated individually. Submissions on the draft regulations indicate the distribution companies are unhappy with treating all connections in a 'one size fits all' way with regard to application approval times.

the production of energy. It will be applied to the highest value combination of uses.

This means that power flow can be bi-directional and the direction of power flow may vary at any point in time. For this to be controlled or predicted requires a mix of generation types and modes in diverse locations plus more developed measurement and control capability. This in turn means that the traditional tapered radial configuration may no longer be appropriate. Networks that are more heavily interconnected or meshed are likely to be more DG capable.

Network Operation and Safety

A regulatory requirement of electricity network operation is the need to ensure the safety of both the field staff that work on the network and also of members of the public.

Operation of a traditional distribution network is more straight forward when a network has only one point of injection. When a part of the network is disconnected, all downstream components of the network will be de-energised. Where backup circuits are available to restore supply downstream of a disconnected or isolated part of a network, the associated connection points are limited in number and under the control of the network owner. The safe operation of a distribution network becomes more complex where there are multiple points of injection. Where infeeds from DG or backup circuits are possible from both ends of, and possibly within, a de-energised section of a network, the possibility of inadvertent re-energisation increases.

One complexity DG adds is the possibility of synchronisation with the grid being lost. Generation will trip 'off line' if a mismatch between generation capacity and load occurs. Generators cannot connect back onto the network automatically i.e. the process is controlled by the system operator. Essentially, the distribution network behaves and is operated in a similar fashion to the transmission grid. The current safety operating rules have been developed for all parts of the NZ system. DG presents no new operating or safety issues that aren't already being adequately managed.

Protection

With the addition of generation embedded within the network, the distribution system can experience new operating conditions and the network design, and particularly the protection design, may need to be modified to accommodate this. Possible scenarios that can arise include:

- an 11 kV distribution network is normally connected to earth through the supply transformer at the zone substation. If a generator connected at 400 V is allowed to backfeed into an 11 kV network that is not connected to the supply transformer, there could be no earth connection on the 11 kV system, creating an unsafe operating condition; and
- if a connection between a distributed generator and the rest of the electricity supply network is momentarily lost and then restored, the mains supply may be out of synchronisation with the generator when power is restored.

Metering

The type of metering necessary for embedded generation will largely be determined by industry requirements or by the commercial arrangements between the generator operator, the electricity purchaser and the network owner. Interval (time-of-use) metering, which measures the energy output in half hourly time intervals is currently necessary if the generator output is sold through the wholesale market.

Where DG is connected to a network and electricity is exported, the generator must ensure a separate record of inflows/outflows of electricity and metering must comply with the rules contained in the DG Regulations [3]. Regulated terms apply in situations where distributor/generator have not negotiated a contract.

The installation of local micro-generation within a customer's own premises may create situations where the customer will at times be taking electricity off the network and at other times be feeding surplus electricity into the network. A standard accumulating three-phase or single-phase meter will measure net consumption (or generation) in such situations. However, the use of these meters in such situations creates commercial problems as the

retailer is in effect buying electricity at the retail sale price. Bi-directional meters that separately measure electricity flow in each direction to obtain power flows are also available.

Network Thermal Capacity

When a distributed generator is connected to a network, the network must have sufficient thermal capacity to deliver the generated power to the load. Network capacity is usually limited by the allowable temperature rise of the lines, termed “thermal capacity”. This means that the surrounding network may need to be upgraded before the generator can be connected. However, situations can arise where the connection of a distributed generator can allow the cost of a network upgrade to be deferred or even avoided.

Consider a situation where power demand located some distance from a GXP grows to the extent that an upgrade of the network delivering electricity from the GXP is required. The connection of a distributed generator close to the load may allow the network upgrade to be avoided. Further, in such a situation network losses will be reduced. The above is a simplistic example, limited by the obligation of the network to be able to meet the power demand at times when the distributed generator is not operating. Nevertheless, situations often arise when the connection of DG can allow network upgrades to be deferred until upgrade is economic or avoided.

Where there are a large number of small distributed generators (of different types and reliable), the need to upgrade transmission and distribution networks to supply the total distribution network load is significantly reduced by the diversity of generation sources. Unless the primary fuel source is common and it fails, the probability of all the distributed generators not being in operation at the same time is low and potentially an acceptable risk.

Network Steady State Voltage Changes

DG has a significant inter-relationship with voltages on a network, and depending on the network characteristics can incur negative or positive impacts on the network. Electrical equipment is designed to operate at a particu-

lar rated voltage, typically 400 volt three phase or 230 volt single phase. If the network voltage is too low, the equipment may fail to operate as designed, while voltage that is too high may damage the equipment, possibly to the extent that the equipment becomes dangerous. The voltage on a distribution network will vary with load, rising as the load reduces and dropping as the load increases. It is therefore necessary to design the network to limit these voltage excursions. In New Zealand, regulations require the voltage at the point of entry to a consumer's installation must be within $\pm 6\%$ of nominal, except for momentary variations under transient conditions.

Whereas in high voltage networks (transmission lines) the voltage fluctuation is primarily related to reactive power flows, in low-voltage distribution networks, the real power flows (and therefore real power production by DG) has significant impact on voltage fluctuations. The fact that network voltages can change significantly as the real power output of a distributed generator is altered can be problematic for a network owner. It means that the voltage at the generator point of connection may need to rise to unacceptable levels to permit the export of the generated power.

This inability to control network voltage independently of real power flow can significantly affect the maximum generation capacity that can be feasibly connected to an existing distribution network, even where the relevant network elements would appear to have the thermal capacity to export the generated power. Also variable power output (e.g. by intermittent renewable generators) can make voltage control on a line quite difficult, even if automatic controls exist (e.g. on-load automatic tap changers on distribution transformers).

Generally this is scenario that would only arise when the generation was significant in scale to the capacity of the network. For this reason there is a regulatory connection design approval process administered by network companies.

On the other hand, situations often arise where the connection of a distributed generator will allow the voltage regulation of a network to be improved. The connection of a generator to a

distribution network can thus be beneficial in situations where the network capacity is insufficient to maintain voltage at the point of entry to a consumer's installation at acceptable levels. Further, if a synchronous generator has the capability to regulate the voltage in its field winding, it can continuously control the voltage at the point of connection.

Where a reliable solution to a network voltage issue can be provided by DG network operators may wish to purchase such services.

Power Quality

Steady state voltage regulation can be significantly affected by the real power output of a generator. It follows that dynamic variation in real power output can cause dynamic fluctuations in system voltage levels. This can be a particular problem for the connection of generators, such as wind turbines, where the real power output is uncontrolled. Since wind turbine power is dependent on the wind speed (theoretically, wind power is proportional to the wind velocity cubed) at any point in time, the real power output will be continuously fluctuating and this could adversely affect system voltage levels. Some variations in electricity production and harmonics by power electronics can cause voltage flicker due to interaction of the real power output with the system impedance.

This is more likely where the fault level of the system is low, i.e. system impedance is high. Situations can also arise where power quality problems on a network prior to connection of a generator can be injurious to the generator itself. Differing power flows in the three phases of a three-phase network could cause additional heating of the generator windings, which if significant could require the generator to be derated, thereby reducing the maximum power output.

Harmonics, or high frequency variations in system voltage caused by the connection of non-linear loads to a network, can cause similar problems. It should be noted, however, that regulations and electrical codes of practice exist that require network owners to maintain the delivery voltage within limits and, with electricity consumers, to keep the delivery or injection of harmonic voltages and currents

below prescribed levels. If the power quality on the external network complies with the regulations, it should not be a problem for a well designed embedded generator.

Transient Stability

Transient stability is associated with the ability of a generator to maintain synchronism with the main grid, following a network fault or step load change. The problem becomes more acute if the network to which a generator is connected is weak, i.e. it has a low fault level. The addition of a generator to a network could add to the risk of a loss of energy supply on the network following a system incident due to the possibility that the incident may cause the generator to disconnect from the grid. This generator disconnection can exacerbate the original problem and increase the severity of the incident from which the network must recover.

Transient stability issues can arise on networks that appear to have adequate thermal capacity to accommodate the generated loads. It is possible to model the stability of a generator following a system disturbance using dynamic simulation software and such modelling is recommended if it is considered that stability could be a problem.

Generation must integrate technically to the distribution system it is embedded into and therefore network owners will have a range of technical requirements that may create limitations to a DG opportunity.

Fault Levels

Rotating plant, including generators, connected to an electricity supply network will feed current into the network under fault conditions. This current is limited only by the internal reactance of the machine and the network within the fault area and can be very large. Clearly, connecting a distributed generator to a network will increase the potential fault current in the surrounding network, possibly to the extent that it exceeds the fault current rating of other current carrying equipment, particularly switchgear and fuses. In such circumstances this equipment must be replaced with higher rated plant, or other remedial measures, such as the connection of fault current limiting

reactors, put in place.

The engineering is well understood and standard solutions exist for all the above issues. The challenge for NZ is that network operators traditionally do not have any experience with generation on their networks and engineering support for investors is limited particularly in the regions. There is a significant learning curve cost hurdle for those first off the block.

Potential Contributions/ Benefits of DG

The value of DG to the network owner is a balance between the benefits obtained from the investment and the costs incurred by the network due to the DG connection [5]. The benefits of DG in distribution networks include deferral of investment, improved system security, improved power quality such as voltage profiles and customer outages and reduction in line losses resulting in increased efficiency of the system [3]. The costs of connecting DG to the network include increased requirement for protection systems, reduction in system security and stability, reduction in power quality and network redundancy [6]. These benefits are also able to be realised from the transmission system and are often of higher value because to distribution systems ability to aggregate and diversify the load presented at a GXP.

CAENZ has done significant previous work quantifying the range of benefits that can accrue to the network owner under optimal conditions [7] The following sections summarise some of this analysis.

Transmission

Transmission networks can benefit from Distributed Generation as it can defer the requirement for security upgrades. Security constraints are generally reached before capacity constraint becomes an issue. Distributed generation (specifically diesel gensets) can be applied to cover the security constraint until upgrade of normal capacity is warranted. Similarly a security constraint can be covered until the duration of the constraint justifies greater expenditure.

The ability to concentrate load and generation, with a higher quality of diversity, at GXPs compared to smaller segments of distribution networks incentivises application of DG to transmission optimisation in priority to distribution.

Distribution

Distribution networks face the same security cost/service issues as transmission networks. However their loads are smaller, more spread out, and more likely to be spur connected. Security provision, via interconnection and redundancy, consistently to all consumers is likely to be beyond affordability. Whereas the upgrade or dual installation of a line or transformer addresses the security of one asset at one location, the security provided by a generator can impact deeper into a network and, if mobile, can be used at several locations. Its security provision will also extend up into the transmission system. In general, security is most effectively delivered at the lowest voltage possible [7].

While DG can improve system performance by being an alternative to line upgrades there are other potential negative performance effects such as harmonics, fault levels and voltage issues. Small scale DG systems often require the use of inverter technology to connect to the network. This technology can introduce harmonics into the system adversely affecting other customers but technology has developed to overcome this issue. Fault levels on networks may increase due to increases in numbers and sizes of rotating machines installed as DG. These machines can increase the fault level of a network necessitating improvements to substation switch gear and fault control equipment.

These upgrades can make the cost of installing the DG prohibitive just as the added cost of transmission upgrade may make centralised generation uneconomic. DG can also create voltage support issues in a network where during light load DG may create an over voltage situation and may contribute to an under voltage situation if the DG were to trip. Additional DG may also cause voltage flicker, an additional issue to be managed by the distribution company.

Capacity constraints within a distribution network tend to be more localized than a transmission network and the reduced load diversity often results in a more peaky load profile. The capital cost of upgrades can greatly exceed the prospects for revenue growth. This is a common issue for long lines remote from sub-transmission support. Constraints may be related to short seasonal loads such as holiday loads. Volt drop problems may only be present for a few hours per day or a few weeks per year. In these scenarios distributed generation, along with other solutions such as capacitors, voltage regulators, etc., can provide temporary relief until the constraint condition exists for sufficient duration to justify a permanent line upgrade [8].

Network capacity constraints can be alleviated with DG connected close to the major regional loads. This depends on how the network is arranged in the major load areas and what type of fuel is locally available to make the cost-benefit analysis worthwhile for the DG investment. For this benefit to accrue, the network company would have to have some level of control or influence on generation despatch during times of capacity constraints.

Adequacy and Security

Security is an issue that affects all levels of the power system from transmission through to consumer installations. In general the availability of more DG in the region has the potential to improve security of supply and network reliability criteria (SAIDI, SAIFI and CAIDI) with local generation supplying local loads through shorter and more robust line connections. If designed appropriately with sufficient generation control, the improved connections can provide consumers with shorter outage times. In certain cases additional line connections will provide a (n-1) security level where this would not be available without the DG connections in the network [8].

Similarly a dedicated DG power supply source close to matching loads has the potential to improve availability of supply by not being exposed to the major network faults and outages. In some cases it is possible to run the DG and matching load as an islanded system for a short time and allow connected consum-

ers to be supplied independent of the major system outages.

Expenditure on security provisions can be very difficult to justify because the duration of contingent events are short and probabilities of outages very low. The traditional full redundancy approach to providing security at transmission level tends to be prohibitive for small loads. Consumers are therefore served with inconsistent levels of security dependent on where they are connected to the grid and in terms of the transmission charges they pay.

In general distributed generation can deliver greater resolution in the security standards able to be provided. Security constraints are generally reached before a capacity constraint becomes an issue and thus distributed generation can be applied to cover the security constraint until upgrade of normal capacity is warranted. Similarly a security constraint can be covered until the duration of the constraint justifies greater expenditure.

Transpower applies much higher security standards (particularly in the core grid) than line companies tend to apply/deliver on their distribution networks. Coordination of these different standards in light of what is actually delivered to the consumer may present opportunity for rationalization and alternatives such as distributed generation.

Commercial/Contractual Factors

Contractual issues cover a wide range of areas from rules and requirements of site access and inspection to lines and connection charges and rebates on transmission tariffs. It is the effect that distributed generation has on the overall power system and how the monetary flows arising from those effects is proportioned that is the most contentious issue when assessing the impact of different DG technologies. A number of these issues are outlined below in more detail.

At the transmission level when the capacity of a Transpower GXP becomes constrained the cost of upgrading the grid connection assets is charged to the users of those assets via the terms and conditions of a Transpower New Investment Agreement. If the demand presented to grid can be constrained to within the

capacity of the GXP then upgrade can be deferred. Capacity upgrade typically involves a significant step increase in the capacity and size or quantity of the assets involved. Load may be growing in relatively small increments, which presents issues of capital efficiency when large investment is required but the capacity increment can only be utilized over a long period.

Distributed generation can contribute in several ways:

- It can improve peak management and therefore allow load to be managed within the constraint.
- Capacity can be delivered in increments that match load growth.
- Capital expenditure can be minimized.
- GXP upgrade can be deferred until there is a significant gap between supply and demand such that the utilization of new assets is sufficient to deliver an adequate return on investment i.e. generation can be used as a “stop gap” measure.

At the distribution level capacity constraints tend to be more localized than a transmission network and the reduced load diversity often results in a more peaky load profile. The capital cost of upgrades can greatly exceed the prospects for revenue growth. This is a common issue for long lines remote from sub-transmission support. Constraints may be related to short seasonal loads such as holiday loads. Volt drop problems may only be present for a few hours per day or a few weeks per year. In these scenarios distributed generation, along with other solutions such as capacitors, voltage regulators, etc., can provide temporary relief until the constraint condition exists for sufficient duration to justify a permanent line upgrade.

Generically, however, one could say that when the DG-installation is based on an intermittent, renewable source, the benefits to the local network will generally be very limited, as the production cannot be relied upon to be available when needed. The situation changes with dispersal of DG throughout a network or feeder due to the complementary energy production nature of differing DG types and uses. Collectively the dispersed generators may be able to provide a more stable generation profile than by a group of closely located units

or a single unit alone. This allows for a greater investment deferral benefit in comparison with non firm generation [14].

Consumer installations also face capacity related connection charges and pay for connection asset upgrades on a use basis. For large consumers, needing a dedicated HV cable connection for example, upgrade costs can exceed the cost of a generator and achieving a capital efficient capacity increment can also be challenging for companies with short risk horizons. Adding distributed generation to a consumer's installation increases the diversity of their load and potentially provides more capability to manage demand.

Connection charges (both fixed cost network upgrade and ongoing lines charges) can involve complex monetary flows between the various parties especially in an industrial/commercial situation. In the absence of standardised contract forms, administering, negotiating and enforcing all payment and billing schedules is a complex process and open to dispute.

CAENZ studies [1, 7] have reinforced the importance of commercial/contractual arrangements in determining final commercial performance.

DG Investment Criteria

Ultimately, the only real investment criterion for distributed generation is profit. The form and size of this profit may be different between different investors but no investment is likely to be undertaken if it will lose money in the long term. There does appear to be some exceptions to this though where perhaps the unit is run as a demonstration model in order to facilitate information exchange or increase knowledge on the installation and operation of DG. Mainpower is one such example where they have a 35 year payback for their PV project on their office roof.

As noted above, profit may not be realised as extra monetary income from the generated electricity but in the form of unrealised (avoided) costs, where load is now supplied via the distributed generation at a cheaper price than previously obtained from the network. Ways of measuring profit may be through an

increase in cash flows or via ‘capturing the retail margin’, where the retail margin is the difference in price between power bought from the retailer and that produced by the DG.

Pricing structures within the industry and regulatory control still have a major effect on people’s preparedness to make an investment. For example, the requirement for network companies to share transmission savings with consumers, rather than DG investors, is a disincentive to network company support.

Sizing of DG is related to the economics of the installation and the intended use. A residential unit is not likely to be large whereas a co-gen unit at a large industrial site will be the largest affordable to give a good investment return. The economics of the installation largely govern the size of installation alongside the application of the generation e.g. is it simply displacing load off the distribution network or is it actively operating to inject onto the distribution network?

The issue of generator siting within the context of the distribution network is vitally important and is discussed further in the following Chapter. DG can be connected at a site where there are capacity constraints, consequently reducing those constraints. DG can also be sited in an unfavourable location resulting in increased congestion on the distribution network. These and many other issues including voltage control, frequency and synchronisation have to be worked through when a distributed generator applies for connection to the distribution network.

The characteristics of the network determine the relative weightings needed to be given to the various cost and benefits arising from a single installation. This, in turn, is influenced by the combination of DG technology type, the technological impacts of the DG investment and the network structure and load profile. DG can influence the characteristics of the network in a positive manner when DG is located and sized in an optimal fashion [10] [11] [12] [13].

Locational Value of DG

Overview

The location of DG within the distribution

network affects the value of the DG investment to both the investor and the network owner [5]. For the network owner the value of DG is in its ability to reduce congestion, defer investment, improve security and increase overall network efficiency. For the investor the value of DG is in security of supply, improved price stability and reduction in energy costs. The value of the DG investment as realised by both investor and network owner is dependent on the location of the DG connection as this influences the size of installation, type of DG technology used, connection costs, pricing policy and avoided costs of investment.

Transmission pricing also has locational factors that affect the value of DG. In some cases generation dispatch will optimise against transmission pricing and in other cases the electricity market will be the main driver of dispatch. Transmission and energy costs are related to each other.

Locational factors also have a dynamic associated with the timing that energy is generated. A pricing premium can be expected during peak loading conditions and in locations where there is a transmission constraint.

Both investors and network companies aim to maximise the value of DG to their business but they approach the problem from different perspectives. The network company uses information about their network characteristics and load profile to influence their connection and pricing policies. The connection and pricing policies are designed to encourage DG investment in the locations where maximum value is realised for the network company. The investor uses the connection and pricing policies of the network company to identify the locations and investment sizes where they will maximise their value of DG. The resulting investment in DG will then alter the characteristics of the network leading ultimately to changes in connection and pricing policy as designed by the network company.

Figure 1 illustrates the connections between the critical factors that influence DG investment value. The diagram illustrates how location of DG is crucial in influencing the value of DG to both investors and network companies.

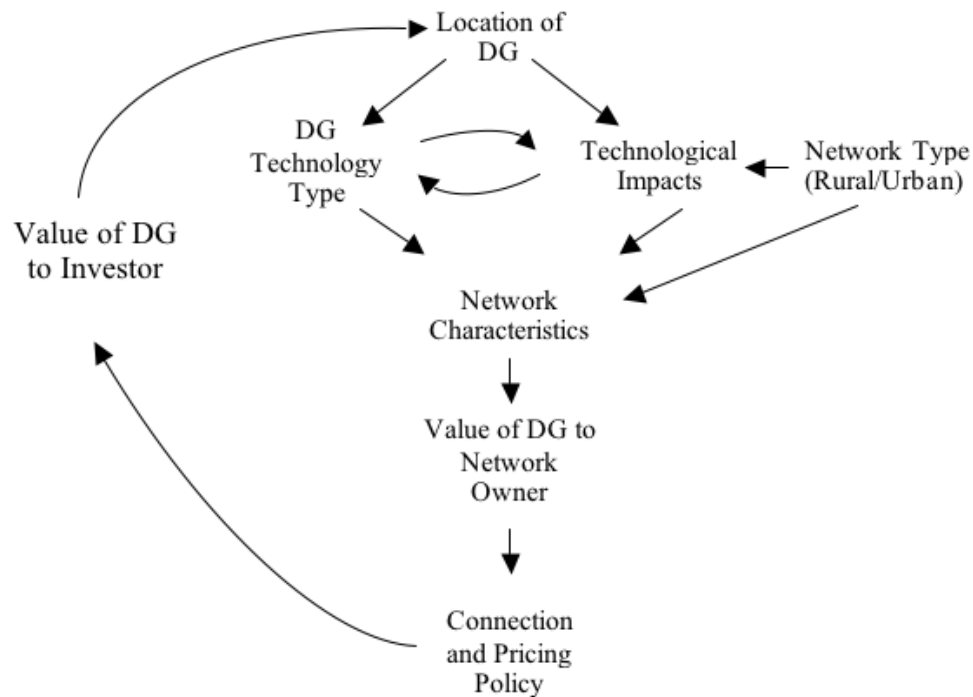


Figure 1: Connections between the critical factors that influence DG investment value

DG Technology Type

The location of available resources for energy production affects the type of generation technology used for DG investments, particularly if the DG is required at a specific location e.g. an industrial site. Technology options include small gas or diesel generators, CHP and micro gas turbines, renewable technologies such as photovoltaic's, wind, hydro and fuel cells [11] [15]. Where the DG technology type utilises waste from an industrial process e.g. CHP or biomass, the location of the waste resources restricts the location and connection of DG to the network. Renewable technologies are particularly restricted by resource location; wind, solar or hydro DG being particularly dependent on resource location and/or weather patterns (dictated by location) [16].

The type of DG technology used affects the technological impacts of DG connection on the network. Variable output technologies such as wind, solar or micro hydro affect the network by having a variable impact on voltage, security and load reduction. In contrast, firm generation from more conventional units, once connected, creates a less variable impact on the network. The variable nature of network impacts affects the value of DG to the network

owner where for example, the non firm characteristic of wind has less ability to defer investment (such as transmission substation or transformer upgrades) than photovoltaic's or CHP due to its variable generation nature [9].

The ability of one type of generation to support another type of installation can result in the value of both investments being increased. For example, the use of hydro storage to firm wind generation. A well planned 'system' would look at developing DG as a balanced and diverse portfolio.

Technological Impacts of DG on the Distribution Network

The technological impacts on the distribution network are many and well documented in the previous Chapter. They include load flows, reactive power flows, line losses, voltage profile changes, fault levels, power quality and system security [17]. Whether the technological impact is detrimental or beneficial to the network is a direct consequence of the location of the DG connection [6] [18] [19] [20].

The type of network the DG is connecting to is an important consideration with regards to the technological impact of DG investments. This is

aply demonstrated in case study analyses reported in Chapter 5.

Rural networks are often weak with lower voltages, lower current capabilities in transmission and voltage issues. Connecting DG in rural areas can improve voltage profiles [21], but conductor impedance can limit the ability to site DG in locations with available resource [22] or require additional sub-transmission infrastructure [5].

Urban networks, which tend to be more interconnected, are more suited to DG due to the greater transmission and transformer capacity [22] but the fault level may increase [23] resulting in required upgrades being detrimental to the economics of the investment. Urban DG has the ability to defer investment in transmission and transformers [22] improving the economics of investment.

Whether the overall investment is valuable from an economic standpoint depends on the location of investment and the network characteristics at that location and the negotiated outcome. The characteristics of the network are largely influenced by the structure and load profile on the network. DG will often result in reduced load on the network and altered network power flows.

Value to Network Company

In determining the value of DG to the network the benefits and costs of specific investments must be individually assessed, as benefits may become costs (and vice versa) depending on specific details and location of the investment under consideration. As such, determining the overall value of DG to the network owner requires in depth analysis of the proposed investment and the changes to the network characteristics due to the DG.

A significant issue is that to date, because of the low penetration rate DG, impacts have been typically examined on a case-by case basis. As the uptake of DG becomes more intrusive, the benefits of continued DG investment need to be quantified through study tools such as simulation, montecarlo analysis [9], options analysis [24], optimisation algorithms [25], load flow studies and policy frameworks. No study tool can by itself

quantify the benefits and costs of DG investment and so many study tools are used simultaneously.

Different networks have different topology, characteristics, constraints and load types resulting in network owners attributing different values to the impacts of DG, e.g. a heavily constrained network may value the ability of DG to reduce congestion than a lightly loaded network that would prefer DG be sited at a location that experiences a high fault level. The differing objectives of network companies in encouraging DG mean that a single method of attributing value to DG is difficult [25] and could be argued to be undesirable.

For example, one of the major benefits to a network of DG investment is deferral of infrastructure investment. An example of how DG may defer network investment is given in [9] where DG may reduce the demand at a constrained feeder by serving local loads, upstream generation and transmission capacity may now be able to serve an increased peak load. The investment deferral is related to a specific investment and region of the network indicating the value gained from investment deferral is highly dependent on the location of the DG connection. The proximity of DG to load influences the ability of the DG to defer network investment. Where DG supplies load locally the power flow through the network is reduced allowing for greater load growth without network reinforcement [9]. DG also competes against generation, transmission and distribution costs giving increased value to DG that is located close to the load [13].

For a network, and local community it serves, independence from transmission cost and electricity price path, remain significant drivers for change towards more DG. It should be noted however that this is the result of the pricing mechanisms that exist. Today's market driven electricity system gives little consideration to technical efficiency and other national benefit issues.

Policy and DG Planning

In assessing the value of DG, the location of the DG within the network is arguably the most important factor in determining benefits and costs to both the investor and the network

owner. The network owner signals through its connection and pricing policies the value they attribute to DG at different locations within the network [26] and as such are able to influence the value of DG to the investor by reducing costs or improving revenue in locations where DG is valuable.

The policies adopted by network companies should reflect the location specific nature of DG by having a location specific tariff structure. This allows the value of DG to the network to be adequately recognised [29]. Using pricing policy to influence DG investors with regard to location and patterns of network use encourage efficient investments and discourage poor investment or over investment [28]. Patterns of network use are related to the time of use nature of distribution networks. Differing DG technology types have different operating patterns, some have mostly firm generation, others non firm or a mix of firm and non firm [29]. By reflecting the time of use nature of both DG and demand in pricing policy, the locations *and times* where DG is most beneficial to the network can be highlighted [27].

Where network connection and pricing policies are not efficient at reflecting the value of DG to the network, the amount of DG deployed within the network could be adversely impacted, the cost of network investment could rise and distortions between market participants could increase [26]. Connection policies should also reflect the need of the network owner to adequately distribute DG in locations within the network that facilitate an overall efficient system [23] show that diversity in location and number of DG installations is important when assessing DG investment as too many DG connections can adversely affect the economical efficiencies gained by the network company.

Issues that hinder efficient policies and delivery of investment signals to investors, are:

- The bundling of distribution and transmission charges into energy retailer tariffs. The charges consumers pay for electricity are set by retailers.
- Pricing methodology that is based on energy volume and the cost of production and delivery.

- A lack of direction until recently with regard to national policy and energy strategy, climate change, efficiency, coordinated governance rules, etc.

Value to Investor

The value of DG to the investor is the balance between costs of the DG including fuel, maintenance and installation and the benefits that can be obtained from the DG e.g. reduced energy costs, increase in security of supply, reduced risk from volatile energy prices and potentially a reduced carbon footprint (if the DG is renewable). The quantification of value by the investor is also dependent on the location of the DG; although in the examples examined in this study DG was located proximate to an available (free) fuel source.

Where fuel sources are easily accessible such as CHP, biomass at landfill etc these locations have a higher value to the investor as the cost of operation will be lower. DG may provide increased security of supply to the load particularly in radial networks where single faults can island parts of the distribution network.

One important factor in assessing the value of DG to the investor is the connection and pricing policy of the network to which the DG wishes to connect. Ideally, the network company should use its connection and pricing policies to encourage DG in locations that offer the optimal benefits to the network in terms of deferral of investment and improvements in power quality and security and to discourage DG in areas where DG would increase costs to the network [26].

The process for connecting new DG is now governed by the 2007 Regulations. Pricing principles covered by the regulations requires charges to be based on the recovery of reasonable costs incurred by the distributor to connect the generator. However, in practice, it is difficult to envisage how opportunity costs might be calculated for any DG connection that acts to reduce overall network efficiency.

DG will have more value to the investor if there is a favourable connection and pricing policy, something that should occur at locations within the network that can obtain the most benefit from DG. On the other hand, investors

should nor expect a free ride where their proposed location is detrimental to network efficiency.

The regulations [3] are intended to encourage DG particularly at smaller scale where existing connection assets are already adequate for DG to embed behind.

DG has the most value when it forms part of portfolio of diverse generation facilities. Network companies can provide operating functions as a service which overcomes the operational overhead of starting a generation business with a single investment.

Location of DG

The location of DG investment and connection is thus vital for influencing and realising maximum value in the DG investment for both the investor and network companies [30]. Where both the investor and network company can obtain maximum value from a DG investment, the more likely DG investment will be undertaken. Experience in The Netherlands has

shown that a 'win-win' solution between network companies and investors, with respect to DG value, improves penetration of DG within a distribution network [10].

One of the most important factors influencing joint maximum value was the geographic location and concentration of DG. Increased concentration of DG resulted in reduced costs to investors, generating an improved economic return. This in turn improved numbers of sales and installations of DG units that increased the concentration of DG within the network [31].

The location of DG is pivotal in influencing network characteristics and consequently connection and pricing policies. These policies are critical in affecting the value of DG to investors and consequently the locations for DG connection and investment. The central nature of location in the DG investment process implies every investment should be treated as unique. There is no 'one size fits all' solution to the planning process [32].

4 DG IN NEW ZEALAND

Commercial DG Models

Figure 2 provides an illustration of the complexity of the New Zealand Electricity Market and the linkages between industry participants.

The continued restructuring of the industry and evolving regulatory arrangements have been reflected by new patterns of investment and activity by the different industry stakeholders. The figure reinforces the complexity of the institutional, market and regulatory arrangements, which ultimately govern industry investments.

Obtaining an optimal solution for the physical delivery of electricity at least cost within such an industry framework is thus fraught with difficulty. The role of DG and the commercial arrangements that drive DG investments is not a simple matter.

DG competes with conventional centralised generation and network capacity expansion based on costs and strategic needs. DG must also compete with a range of demand-side options that can reduce electricity demand and/or peak capacity requirements in the

transmission and distribution networks.

However demand-side options can also be used to complement DG investment adding more diversity and opportunity for optimisation.

More recently DG is seen as a means of utilising generation from renewable energy resources such as wind and small-scale hydro in situations that would otherwise not be economic if sized to meet individual demand alone.

Previous work by CAENZ [1] suggests that DG investment in New Zealand is likely to have to embrace systems of less than 1 MWe. This includes a range of different applications as follows³:

- Residential owners concerned with improving energy efficiency and reducing their energy costs and prepared to invest in small scale wind, solar or micro hydro generation.

³ As customary in the electricity sector 3 types of end-use categories are used: residential, commercial (including government & commercial buildings, hospitals, retail/shopping centres, etc) and industrial

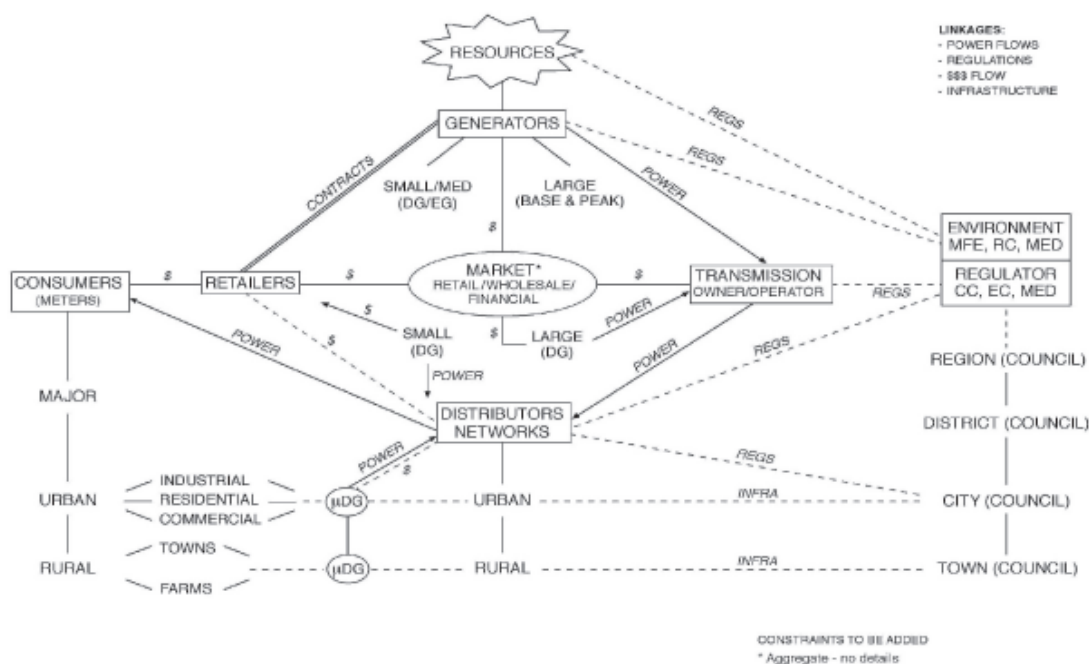


Figure 2: NZ Electricity supply industry - participants and linkages

- Currently topical issues such as climate change, peak, etc. are encouraging communities to look at sustainability of energy supply as community initiatives.
- Large industrial and commercial enterprises with high energy needs, high security of supply requirements and/or those that operate technology suitable for cogeneration plant operation. Pricing risk is often a consideration as generation is a form of energy market hedge. Having a host load is often required and heat may be the dominant energy element.
- Other industrial and commercial owners of backup generation purchased for their own stand-by or emergency supplies.
- Lines Company investments in network reinforcement or to support network diversity. Generally these investment form part of normal asset management strategy. Consideration of alternative solutions is a prescribed Asset Management process.
- Isolated residential or small scale units eg. Rural settlements or agricultural industries. Distributed generation may give these investors cheaper energy and/or a more reliable supply by avoiding network connection costs. These are sometimes referred to as Remote Area Power Supplies or RAPS. Governance of these systems lie outside the regulations.
- Institutional owners such as District Council trading entities or other public entities to improve energy utilisation or reduce energy costs.

DG projects of the size and applications listed above are likely to have the following connection characteristics:

- 1. Non-export DG-projects** behind existing load. These projects generate less than the energy requirement of the load at the site and therefore have no or very little energy surplus to export. The value of the energy generated is basically the net retail price of the replaced electricity. From a commercial perspective no export contract is necessary assuming technical standard compliance is procured through retail energy contracts. From a network perspective, the DG-project cannot be seen, but for the reduction in load and no specific DG-connection contract is necessary. However, if well managed, the DG-project can significantly reduce load peaks, with potential advan-

tages for both the network company (reduced network peaks) and the host load (via reduced peaks, i.e. reduced costs). Where network tariffs are based on energy volumes distributed and not costs; reduced import volumes can mean significantly lower income for the network company.

At the network level such investments create a distortion to efficient investment within the network. If the network company already has a high investment sunk into the connection capacity for much larger import volumes or peaks, and this still needs to be maintained in case installed DG plant is malfunctioning, the network company may not be willing to reduce connection charges. Most cogen-projects fall into this category and as such benefits from the investment are rarely fully realised. Small, residential PV and solar water heating systems would generally also fall into this category.

- 2. Part import, part export generator.** This typically covers projects with significant variation in load and/or generation. In this case import and export both occur. The average value of the energy generated is somewhere between the net retail price of the replaced electricity and the wholesale sales price. If connection capacity is sized for maximum import requirement then generation export will be constrained to the same peak capacity. Both import and export need to be metered separately (under present rules) and a contract for both streams is necessary with a retailer (generally the same) unless size allows direct sale to the wholesale market. There will generally be a spread between the import and export tariffs to cover retailer margin and risk.

The timing of when generation is available and when load is peaking relative to the wholesale market can deliver significant premiums. When prices are high windfall profit may result from increasing the level of base loading.

From a network perspective, there is little justification for an import-export connection to be treated differently in terms of connection capacity as the cost of the connection asset generally doesn't change if it is for power flows in both directions as compared to import only (except with respect to fault level currents, islanding,

switch off during maintenance and possibly areas with significant DG where total max export can be larger than total import).

Regulation prevents network companies charges for generation connection assets when no actual additional investment is required i.e. cannot charge for the use of an existing connection. Landfill/sewerage gas and some cogeneration plants fall into this category, as well as industrial customers with intermittent generation.

3. **Export-only DG-projects.** This includes most small-hydro, wind and (small) geothermal plants. Commercially these projects have to sell their production at wholesale price (unless they can manage a contract with another user within the same distribution network), which is generally significantly lower than retail prices. Network companies are limited in their ability to trade energy directly to consumers and so network company-owned DG investments can only sell their output to retailers who generally own competing generation.

Network companies therefore have a reluctance to investing in DG unless there are strong network benefits to be gained. These are the projects where DG-connection rules have the most impact, as specific connections generally have to be made and locations are often remote. Connection costs can therefore be high.

It is this category where much of the present regulatory debate is focused with respect to regulated retail and connection contracts. A relatively large number of these projects have been installed in New Zealand in the past. Significant opportunity still exists and needs to be unlocked if New Zealand wants to use its renewable energy potential to the maximum. However, challenges with these projects are also large, as generation resources are generally intermittent (i.e. not providing reliable network benefits), capacity utilisation is low, i.e. high network capacity per produced energy; and many of these projects are in areas remote from network access, where generation resources are available but with higher probability of technical and economic connection issues.

4. **Back-up and peak-logging (diesel/gas) gensets.** Generally existing for backup; sometimes used for peak-logging (consumer peaks); can also be used for network

support (network peak-logging) and transmission cost management. This type of plant can also be used to firm other generation, such as wind and hydro with limited storage if managed as part of generation portfolio. Plants need to run occasionally for operational reliability.

5. **Investments in diesel gensets** specifically for network support purposes: these can be either fixed or mobile and include stand-alone gensets for network support during outages and maintenance back-up activities. Many network companies have one or two of these gensets available on stand-by.

Currently there is sufficient DG penetration and market maturity to be witnessing the application of DG to secondary opportunities. For example at a small GXP's a generation facility in the 1-5MW size band (or a number facilities summing to this size) may be able to export to grid particularly when demand is very low in the early hours of morning. The 5MW Waihi Hydro Scheme at Wairoa exports approximately 200,000kWh's back into grid per annum. Industry rules need to consider this reality without imposing excessive hurdles for such small volumes that might result in unnecessary hydro spill.

In this respect DG is penalised by treating it on a stand-alone basis. Instead, it should be treated as adding diversity to the load base and recognised that it can add value to the whole system. CAENZ studies strongly suggest that DG should also be considered as part of a portfolio of all generation connected to a network where it can add value to other generation investments.

It is important also to note that NZ has a very concentrated energy market with approximately 1% of customers accounting for approximately 70% of the total industrial and commercial load. Members of the Major Electricity Users Group (some 20 plus firms) constitute nearly 30% of all demand in New Zealand [33] and produce nearly 1200 GWh/y of their own generation. Mostly this generation is used on site through co-gen plants or diesel generators in order to reduce their electricity requirements. A number of these users have the ability to offer their load reduction services to the reserve markets or surplus generation to the wholesale electricity market pool. Notable

is that in the last decade or so the contracted interruptible (industrial) load has increased from ca 150 to ca. 550 MW⁴.

Existing Distributed Generation in NZ

There is considerable existing distributed generation presently, although exact amounts vary. According to the MED [34], DG is presently contributing to about 15% to 20% of our electricity supply. Annex 1 provides an overview of known connected DG-installations that add up to around 12% of generation capacity in New Zealand. It is also estimated by CAENZ that about 8% of electricity consumed is from on-site cogeneration [1], not connected.

These numbers are subject to significant uncertainty, as early DG investments have occurred largely on an informal basis. Existing DG-installations have been installed in New Zealand in roughly four 'waves':

- First electricity (municipal) suppliers before interconnected system (<1940): hydro or steam turbines⁵
- The second wave of DG in New Zealand came with government support for the construction of small (around 30 MWe) hydro schemes that some Power Boards and Municipal Electricity Departments were encouraged to build during the 1950s and later.
- Industrial co-generation facilities were the third wave of DG. These projects typically involved large-scale investments, mostly gas-fired, and which still contribute to a significant share of the DG market. This market remains under exploited with quite attractive niche opportunities involving smaller scale generation yet to be ex-

ploited. Co-generation has been largely based on diesel as a fuel, landfill gas and some natural gas.

- The present use of diesel standby sets as exemplified in the Orion case study is the main thrust of recent DG investment to assist in managing network peak load constraints. There is a substantial amount of standby plant already installed. The capital cost is sunk and furthermore there is a need for these installations to be tested at intervals to ensure reliable operation.

With the reinforcement of Government renewable energy policy we are now seeing a new (potential) wave in DG based on renewable energy forms (especially wind, solar, small-scale hydro and geothermal). This is being actively promoted by government.

Anecdotally, it would appear that there are large numbers of new distributed generation projects at the development, pre-development and conceptual stage. But whether these come to fruition remains to be seen. A few of those known to CAENZ are outlined below to indicate the variety of potential distributed generation options.

- Windflow Technology, a manufacturer of wind turbines, has in the recent past built a pre-production 500kW windmill at Gebbies Pass, near Christchurch. It is now progressing a wind farm project, at a site near Palmerston North and promoting development at a number of other sites around New Zealand.
- Genesis Power is now in the process of developing an 18 MW wind farm on Awhitu Peninsula, south of Auckland. The company is also currently constructing a 90MW cogeneration plant with Norske Skog at its Kawerau Mill, burning biomass and gas to supply steam and electricity to the site.
- Meridian Energy is investigating a number of potential windfarm options, including a joint venture with Comalco to assess the potential for a windfarm at Tiwai Point. It has recently commissioned the first stage of its Whitehills wind farm and is in the consenting process for its large grid connected project Hayes in Central Otago and the West Wind site near Wellington. It is investigating using wind energy to balance its hydro capacity.

⁴ From CAENZ [1]; "sustained (1 minute) and the fast (under 5 seconds) interruptible response. A summary of the maximum quantity of interruptible load currently procured by the system Operator is approximately (2003):

Island	Fast (FIR)	Sustained (SIR)
North	344 MW	804 MW
South	45 MW	90 MW

Note that it is up to each Service Provider to determine whether or not they wish to offer their maximum quantity of interruptible load when trading on the spot market.

⁵ New Zealand. The first introduction of electricity at Reefton in 1888 was from local dedicated hydro electricity generating plant. Electricity was generated and supplied for local consumption. The technologies were either hydro or steam turbine.

- Northpower owns and operates the Wairua (3MW) hydroelectric power station near Titoki. It has undertaken studies into the feasibility of extending the power station to increase its capacity to 8-12MW. Northpower has also investigated a 10-20MW wind-generation power station.
- WEL Networks and Green Energy have announced a joint project to build a 1MW plant that will use Horotiu Landfill gas (near Hamilton) to generate electricity. Hamilton City Council will supply the gas and buy back the electricity.
- Unison Network is considering investment in a range of projects ranging from 500kW to 2MW capacity. It has announced it is investigating a wind-driven power scheme at Te Pohue, on the Napier-Taupo highway.
- Centralines and Meridian Energy are investigating a 10MW hydro-electric power scheme near Otane, central Hawke's Bay, with associated irrigation. Any scheme would be several years away.
- The Wairoa District Council is investigating new power station options to meet a needed 2 to 3 MW additional capacity for the Wairoa District. Options being investigated include: a 3MW wind farm at Mahia; a new hydro power station on the Mohaka; a gas turbine in association with the development of Wairoa gas; installation of a 3MW steam turbine generator to an existing boiler at the Affco-Wairoa plant; and installation of a 10MW steam boiler with a 2.6MW turbogenerator, powered by biowaste, at the Solid Timber Building Systems Plant, Wairoa.

DG Regulatory Environment

Current Status of DG Regulation

The government announced in May 2003 their intention to regulate minimum terms and conditions for connection of distributed generation. The electricity Governance (Connection of Distributed Generation) Regulations came into force on 30 August 2007.

Some of the main aspects covered by the Regulations include:

- Specified process for obtaining approval to connect and regulated terms that apply to exemptions to connection contracts entered into outside the regulated terms.

- Disputes resolution processes.
- The need for distributors to act at arms length regardless of ownership or beneficial interest.
- Transitional provisions.

There are also 5 Schedules to the Regulations covering important aspects such as:

- Processes, including timeframes, for obtaining approval to connect.
- Regulated terms for connection of DG in the absence of contractually agreed terms.
- Default dispute resolution process.
- Pricing principles.
- Prescribed maximum fees.

The purpose of the regulations is to enable connection of distributed generation where connection is consistent with connection and operation standards. The regulations set out pricing principles covering issues such as:

- Incremental costs of connection less avoided/avoidable costs.
- Approaches to avoided costs.
- Incentives for others to free-ride where generators pay for spare capacity.

The approach used is an incremental cost approach. Generators are expected to pay the incremental costs of connection to the network, less any avoided/avoidable cost benefit the generator brings by connecting. Incremental costs are net of transmission and distribution costs that an efficient service provider would be able to avoid as a result of the connection of the distributed generation.

Part of the issues surrounding the treatment of these costs is the requirement that a second (or further) generator that connects to the distribution network and utilises a network upgrade financed by the first generator must pay for a portion of the network upgrade as financed by the first generator. This payment back to the first generator is suggested to be paid by the distribution company by means of a reduction in connection charges. Distribution companies are hesitant about this requirement due to costs incurred in administering it and the unknown calculation methods. Calculating the payment could easily be disputed.

In addition to the above the Electricity Commission has published its expectations [35] on the terms and conditions that should apply between retailers and domestic consumers being supplied delivered electricity under an interposed agreement. It has also published its expectations on the terms and conditions that should apply for the purchase of small surpluses of electricity from small scale distributed generation [36].

Retailer involvement in distributed generation is via the purchase of electricity that is injected into the distribution network. Often the retailer will only purchase at the spot price from the nearest GXP, especially if the GXP is not constrained in any way. Expecting the retailer to pay more for distributed generation would only be viable where the distributed generation can facilitate the opportunity for the retailer to increase their energy sales, perhaps through reducing capacity constraints in the distribution network or encouraging more demand usage.

MED in their 2003 discussion document [34] noted that this barrier particularly affects renewable energy sourced generation; such as wind, small hydro and solar generation, as guarantees cannot be given on stable supply. Renewable distributed generation is often non-firm generation where it is difficult to contract for a set amount of energy injection when the method of electricity production is intermittent e.g. solar, or wind. This makes the agreement of a sale and purchase contract between retailer and distributed generator difficult to obtain. There are, however, indications that some retailers are willing to be flexible with the Photovoltaic Association (now incorporated as part of the Sustainable Electricity Association New Zealand) having negotiated a zero spread arrangement for residential DG with Contact. That is Contact will pay the retail price for fed-back electricity for < 5kW residential installations

DG Pricing Structures

Basically, there are two main options for obtaining an energy supply contract for DG, one is offering the energy to the clearing manager and selling into the electricity market pool the second is to negotiate a contract with a retailer for direct sale, i.e. obtain a physical

supply contract at pre-arranged prices [37]. Selling to the clearing manager is unrealistic for small distributed generation due to the tiny amounts of power being sold and the prohibitive financial requirements of being a market participant. Negotiating a contract for sale to a retailer is the most suitable option but anecdotal reports indicate this may not be easy to achieve at desired price levels. New Zealand's major retailers are mostly 'gentailers', companies that own both generation and retail operations. These companies have a natural hedge with themselves resulting in a thin hedge market. The demand for hedges is often small with retailers not willing to pay someone else for energy that they themselves can produce.

In situations where contracts are successfully negotiated, the price paid for energy supplied is often very close to the wholesale clearing price of the closest GXP node, resulting in the retailer capturing the entire retail margin on the energy and the distributed generator making a loss, or very little profit. Distributed generation is often more expensive to produce due to its small scale nature and the wholesale price is often below the cost of generation.

This is an allocative issue, where the retailer treats the energy price as if it is being delivered at the GXP and will still incur the costs of distribution across a network and wide customer base. On the other hand, the DG investor sees generation as targeted to a specific load within the network.

If the distribution network GXP capacity is unconstrained, then receiving the wholesale price for DG seems reasonable as why should a retailer pay more for distributed generation when they could pay less (the going price) and get it from the grid. Conversely, if the distribution network is constrained in some way and the DG is able to supply more customers than otherwise, they should receive a premium for this service to the retailer.

Network Connection Charges

In this study we have used the case study examples to review the different ways in which distribution networks apply connection and use of system charges and their impacts on the

economic viability of the selected case studies.

The regulations limit connection charges to a reasonable estimate of the portion of capital investment and operating costs that the connection of the distributed generator has contributed to, as well as an assessment of any consequential avoided costs. These costs and assessments may include both shallow and deep connection costs.

One issue facing the DG investor is that transmission charges are a 'pass-through' cost to the local distribution companies and it is often difficult for the investor to realise this value as a revenue stream to their own project. Currently the distribution company receive the reduction in interconnection charges, which are normally passed through into reduced revenue requirements in setting charges to retailers. Depending on the contract between the distribution company and the distributed generation owner that distributed generator may receive all, part or none of those savings. Allocation of these costs will always be difficult.

For the distribution companies to be able to

rely on such a generation solution then there needs to be an obligation on the generator not to withdraw their solution if they are to expect a full share of the benefits created. This, again, can be difficult to guarantee.

Another key issue is the application of the Grid Investment Test process that applies at present. Anecdotal evidence suggests that the current interpretation of the test creates a bias towards transmission solutions to the detriment of DG solutions. Orion, for example, report [38] that a 10 MW DG investment was not able to proceed through not being able to arrive at satisfactory contractual arrangements with the Electricity Commission. Instead, it should be possible to offer DG operators long term contracts for transmission support that allows DG solutions specifically targeting transmission constraints. Transmission pricing locks in long term benefits for line solutions via sunk cost recovery (i.e. charge for lines even though they may subsequently become redundant) but yet won't guarantee long term positions for generation solutions. The investment risk position is, thus, substantially biased.

5 CASE STUDY ANALYSIS

Six differing DG investments are presented here as case studies. They represent a cross section of the technology types, operational characteristics and locational aspects of DG investments. The studies are considered in three groups, each group representing a network company. Each study is presented from the point of view of the investor, investigating costs, revenue, connection pricing and charges, taxes and the return on investment period.

Powerco Case Study

General Parameters of Case Study

The Powerco case studies are two examples of independent DG investment within the network without line company interest. Powerco itself has little interest in furthering DG on its network due, in some extent to:

- The robust nature of its network as benchmarked against its asset management objectives i.e. it considers its security and reliability performance adequate. DG investment is of little use to Powerco for reinvestment or capacity reasons across the majority of its network and so it would see little point in encouraging DG investment in locations where it does not provide a benefit to the company.
- Current levels of DG on its network and interest from third parties suggest that line company interest is not required to facilitate the development of DG.
- Transmission constraints aren't strong

drivers in this case and the commercial imperatives of this company treat transmission as a pass-through cost issue.

- Regulatory control of the company prevents it achieving the use of capital investment hurdles required by its owners and it has other less regulated investment opportunities available to it (including Australia).

There is an exception to the above, the East part of the network (especially Coromandel), which is constrained.

Description of Line Company

Powerco is the 2nd biggest gas and electricity network company in New Zealand (by customer connections) and the largest in length, and the only one that is completely owned by a public-listed company (BBI). Powerco is also developing a gas distribution and retailing division in Tasmania. BBI is a major global owner of transport and energy infrastructure (Europe, USA, Australia, New Zealand).

Powerco's Mission Statement is "to provide safe, reliable and economically efficient electricity and gas network distribution services whilst achieving sustainable earnings" [39].

Description of Network

Powerco's distribution network covers the upper-central, central and lower areas of the North Island, providing energy to approximately 400,000 consumers; this represents 46% of New Zealand's gas connections and 16% of its

Consumer connections	304,471 customers (electricity network only)
Network area	—
Lines and Cables	27,000 km
Number of GXP's	25
Zone Substations	101
Total electricity	4,201 GWH
Peak demand	677 MW
Load factor	75.7 %
Connection density	11.24 connections per km of line

Table 5.1: Network Characteristics for Powerco (Source: Powerco's AMP and disclosures)

electricity connections. The region covers Taranaki, Wanganui, Rangitikei, Manawatu,,Wairarapa, South Waikato, Tauranga, Thames Valley and Coromandel regions. The network, itself, serves a range of demands from isolated rural areas to major cities and industrial zones such as Kinleith Pulp and Paper Mill and the Tauranga Port.

The specifics of the network are given in Table 5.1.

Due to “confidentiality and commercial sensitivity” Powerco does not provide detailed information of its large customers. Clearly, one such customer will be the Kinleith Pulp and Paper Mill, which has its own 11kV distribution network consisting of 58 km of overhead lines.

The Powerco network is larger and more dispersed than many other networks in the country. Unique features include: (a) the network is geographically dispersed and (b) the company is limited in respect of its ability to optimise the network as a whole. Thus DG investment can only be looked at from a localised perspective.

The network is best considered as two regions due to different growth patterns across the north island. The eastern region is more dynamic and Powerco expects annual electricity volume and peak demand to grow at 3.9% and 3.2%, respectively, until 2008. The western region is expected to have slower growth at a rate of 1.0% and 0.9%, respectively. In this regard the Coromandel region is the most favoured area for DG investment, due to its high growth, limited infrastructure and seasonal peak demands associated with holiday making. Other areas of the network are more robust and thus far less attractive for DG from a Powerco perspective.

The two case studies that are looked at here are based in Palmerston North (Manawatu) and Wanganui, both areas of low demand growth. This suggests that these areas are not ideal for DG investment from the company perspective.

According to Powerco’s AMP [39] the present network configuration allows some operational flexibility, but the level of security provided in some areas does not comply with Powerco’s security of supply criteria. They make the

following points:

- Taranaki, Manawatu and Wairarapa regions have most of their substations at or near the security level required by Powerco standards. They have the required backup capacity in transformers, and their transformer utilisations lie between 55% and 56%;
- Wanganui security levels are lower, with 7 of its 15 substations currently at A2 (without supply for repair time) security. As transformer capacity for backup has not been provided in these cases, utilisation is higher at 62%;
- At Tauranga, 3 of 12 substations have A2 security, and utilisation is 73%;
- In the Valley Region, 16 of the 27 substations have A2 security, and transformer utilisation is 82%; and,
- Many substations have lower than desired security levels. Those that are only marginally lower will be upgraded along with other substation work, but urgent attention is being given to those supplying industrial or commercial loads.

Note that Powerco describes A2 security as “supply [that] may be lost in the event of the outage of one major element of the subtransmission network. Supply cannot be restored until the faulty element is repaired or replaced”.

Security provision is therefore interpreted as tending towards that expected in a rural network with limited interconnection opportunity. This is below that expected in urban networks. Powerco has an average connection density at the high end of the range for rural networks but also supplies some relatively large regional cities. One issue with large networks with a lot of diversity is that their disclosed performance can average out quite poor service delivery in some locations. Further disclosure information is not normalised between networks and therefore is invalid for comparing one network to another.

Network reliability is higher in urban areas where connection density is greater (due to lower economic and technical constraints), thus in areas of greater demand faults are able to be dealt with quickly, in areas of low density reliability can be poor.

Network Issues

A particular feature of the Powerco network is its vulnerability (design robustness) to weather events and the geographic challenges these can present to fault response.

Adverse weather events can have a material impact on reliability for any network. One can assume that such events will be of longer duration than typically would be seen for other forms of outage. However, the question that arises is the extent to which these factors are properly addressed in engineering design and work practices. DG investment/stand-by-power may be appropriate for the more remote or stringy parts of the network for realising uniformed resilience and reliability. Further DG can offer low cost alternatives to security than network duplication and interconnection.

In this instance Powerco operates to a commercial mandate where there are no requirements to be delivering minimum standards of security and reliability only to maintain service levels relative to pricing path.

Powerco is having to address much stronger growth in the Tauranga and Thames Valley networks (Eastern Region) compared to its network in the southern North Island (Western Region). Furthermore, growth in the Western Region has been slow with most growth restricted to urban localities. In the Eastern Region a broader growth pattern is seen; growth is caused by urban development, energy intensive and seasonal dairy practises, and the increasing trend of this region of the country to be used as a holiday or life-style destination.

Growth related to holidaymakers tends to create short-term load peaks restricted to holiday periods and weekends. Over recent times growth in peak demand has been observed to outstrip growth in energy use, the exception to this has been the eastern side of the Coromandel Peninsula and the southern Wairarapa. Peak and low duration loads can fail to generate sufficient new revenues (via energy related tariffs) to fund network capacity upgrades. Areas that can't justify investment to

Company	Site Name	Export Capacity
Ballance Agri-Nutrients	Kapuni Urea Manufacturing Plant	2.6MW Generator (non-export)
Cheal - (Austral Pacific)	Cheal - (Austral Pacific)	0.6 MW
Drysdale Hydro	Drysdale Hydro	150kVA
Genesis Energy	Hau Nui Wind Farm	3.7MW
Genesis Energy	Hau Nui Wind Farm	3.7MW
Genesis Energy	Kourarau Hydro	0.9MW
New Zealand Energy	Opunaki Hydro	320kVA
New Zealand Energy	Ratahei Hydro	220kVA
NZ Windfarms	NZ Windfarms	?unknown
PNCC	Turitea Hydro	180KW
PNCC	Totara Road Hydro	1MW
PNCC	Landfill Gas	1 MW
Swift Energy NZ Ltd	Rimu Production Station	1.2MW
Trustpower Generator	Tararua Northern Wind Farm	34MW
Trustpower Generator	Mangorei Hydro	4.5MW
Trustpower Generator	Patea Hydro	31.4MW
Trustpower Generator	Tararua Southern Wind Farm	34MW
Trustpower Generator	Motukawa Hydro	4.6MW
Trustpower Generator	Little - Motukawa Hydro	300kVA
Ballance Agri-Nutrients	Mount Maunganui Plant	Non-export Generator

Table 5.2: DG within the Powerco-Network (Source: ??????)

meet demand peaks are even less likely to justify investment in security.

Holidaymakers who come from cities expect city service levels and don't want their holidays impaired by power supply issues. Reliance on tariffs based on energy volumes and not asset cost, contribute to this issue. In these circumstances DG can sometimes provide lower cost solutions.

According to Powerco's AMP [39] there is a capacity shortfall in the Tauranga network that is being dealt with by building a new switching station at Hairini and upgrading GXPs.

DG Profile within the Network

Although the Powerco-network has most of the existing NZ wind farm capacity connected to it (Manawatu and Wairarapa regions) and several small-scale hydro and cogen-installations (totalling more than 125 MW, see below), Distributed Generation is – at present – not a major contributor to Powerco operations, i.e. it tends to be owned and operated by other parties and therefore is not necessarily optimised to address network operating objectives.

It is also worth noting that the number of DG-connection requests received over the last three years is approximately 1 per month (this is higher than before), but DG-projects are installed only at the rate of 1 or 2 per year. Independent generation investors face the hurdle of firstly establishing a network connection but more significantly resolving energy trading or energy purchase agreements with retailers. This is an issue of coordinating these requirements which a lay person struggles to achieve and there is a lack of support capability within consulting, network, and retailer organisations to support investors i.e. the industry as a whole does not present a coordinated, consistent, 'one stop' shop for DG investors.

Until a few years ago no clear, uniform Powerco policy existed with regard to the connection criteria and tariffs for DG. This is a common scenario across the country as networks who haven't been asked to connect DG haven't necessarily thought it through. The necessity of a robust connection and pricing policy in signalling DG value to both investors and network companies has been detailed in the DG literature. Where policy is new, untested or

under development there is greater uncertainty for both investor and network company in assessing long term benefits and value of DG, potentially reducing or limiting uptake of investment opportunities. This issue is even more exaggerated in small networks where there is less probability of those within the community capable of initiating such a proposal and less expertise within the line company to consider the possibility or support the proposal.

In 2006 (in the context of MED signalling its intention to regulate) a new policy [40] was developed after consultation and coordination with, among others, Vector and Orion. The tariff base is set out below, but includes rebates for Avoided Costs of Transmission (ACOT) and rebates for peak generation in constrained areas.

Powerco has briefly investigated installing diesel-gensets in the Eastern Region (especially Coromandel Peninsula), where network constraints are highest from demand peaks in the summer tourist season. However, ACOT alone wouldn't warrant such investments and Resource Management issues are also deemed to be significant, especially for permanent installations. It is recognised that in future when network upgrades become necessary in this area, postponing lines investment could tip the balance towards some incremental DG investment. Powerco's interest in encouraging DG in this and some other constrained areas (particularly Tauranga and Coromandel) is clearly reflected in their DG-policy.

Powerco also states that where a long line connects to a limited load they intend not to replace these lines, but rather investigate alternatives such as local generation. There are 10-20 locations on the entire network where this would be considered. The consumer's right to supply can override decision making on the basis of least cost most efficient solution.

Powerco DG policy

The 'PowerCo Distributed Generation (DG) policy (2006)' is set out below. The policy is split into 3 categories:

- Connections < 10 kW
- Connections 10 kW to 1 MW
- Connections > 1 MW

Conditions and tariffs for connections greater

than 1 MW will always be calculated on a project-specific basis, but the pricing principles are similar to that which applies for 10 kW to 1 MW installations. The procedure for connections less than 10 kW is a simplified version of the other two categories. In this document we will therefore only discuss the policy for connections 10 kW to 1 MW.

Procedure connections >10 kW

A Enquiry

At this stage many developers don't yet know the exact nameplate capacity and technical configuration of installation. The aim is to establish the main technical issues especially

relating to capacity of line in question, maximum demand and potential voltage issues; and the order of magnitude for connection costs and potential rebates.

B Specific studies

Depending on the size of the installation and the state of the network in the connection area, the next stage in many cases involves a more specific load flow study to establish influence and conditions of connection. These studies are done at the cost to the developer proposing the DG-installation (with 10 free Powerco-hours). If the generator is small (often < 500 kW) and network capacity in the area is

Akura	E	Hatrick's Wharf	E	Milson	A	Taupo Quay	C
Alfredton	A	Hau Nui	D	Morrinsville	E	Tauranga City	E
Aongatete	E	Inglewood	A	Motukawa	E	Te Ore Ore	E
Arahina	E	Kai Iwi	A	Ngariki	A	Te Puke	C
Awatoitoi	A	Kairanga	A	Norfolk	C	Thames T1	A
Baird Rd	B	Kaponga	B	Omokoroa	E	Thames T2&T3	D
Beach Rd	D	Kapuni	E	Otumoetai	D	Tinui	C
Bell Block	A	Kauri Point	A	Paeroa	D	Tirau	E
Blink Bonnie	A	Keith St	A	Papamoa	E	Tower Rd	E
Browne St	E	Kelvin Grove	A	Parkville	A	Triton	E
Bulls	A	Kempton	E	Pascal St	A	Tuhitarata	E
Cambria	D	Kerepehi	E	Piako	D	Turitea	A
Cardiff	A	Kimbolton	D	Pohokura	A	Waihapa	A
Castlecliff	A	Lake Rd	E	Pongakawa	A	Waihi	E
Chapel	D	Lakeside Midway	+ A	Pongaroa	A	Waihi Beach	E
City	E	Livingstone	C	Pukepapa	A	Waihi Rd	A
Clareville	A	Main St	A	Pungarehu	A	Waiouru	A
Cloton Rd	A	Manaia	A	Putaruru	D	Waitara East	A
Coromandel	E	Mangamutu	E	Rata	A	Waitara West	A
Douglas	A	Maraetai Rd	B	Roberts Ave	B	Waitoa	A
Eltham	C	Martinborough	A	Sanson	A	Walton	E
Farmers Rd	C	Matatoki	B	Tahuna	E	Wanganui East	D
Featherston	C	Matua	D	Taihape	A	Welcome Bay	C
Feilding	A	McKee	A	Tairua	E	Whangamata	E
Gladstone	E	Mikkelsen Rd	E	Tasman	B	Whareroa	A
						Whitianga	E

Table 5.3: Powerco's Substation Location Rebates (Source: Powerco DG Policy)

more than sufficient (and no expected voltage issues), no detailed load flow studies are required. However, protection systems will always be reviewed to ensure disconnection during faults and maintenance.

Generators above 500kW are always required to have a SCADA-connection so that the control room can see in real time what the generator is doing to ensure there are no safety concerns – and to understand growth and loading issues in the local area.

C Contracting

If the DG developer wants to go ahead, a proposal and contract are developed. Installations under 1 MW derive from a standard policy with connection tariffs and rebates per substation and ACOT calculated per GXP (see Table 5.3). The main aspects of this policy are:

- New assets specific for the generator are to be paid by the generator. However, often the developers provide for the equipment to be finally owned and maintained by the lines company.
- No fixed connection charges (i.e. charge/day).
- The connection charge rate per region (eastern or western). Powerco's western region is \$9.50/kW/month (less in eastern region). The charge is determined using an average of the 12 highest peaks (one per day) over a rolling 12-month period for the generator.⁶
- Location rebate: \$/kW of generation Coincident with Maximum Demand (average 12 highest peaks). The rebate per kW varies per Powerco-substation depending on the expected capacity usage for different substations as projected in the medium term Asset Management Plan; the categories vary from A (sufficient spare capacity for the coming years and no rebate) to F (highest rebate because substation is expected to be loaded at more than 100% in short term).^{7, 8}

⁶ Generation behind load is to be charged on the higher of Load Anytime Demand (average 12 highest peaks) or Generation Anytime Demand (average 12 highest peaks).

⁷ Each zone substation on the Powerco network is assigned a location rebate grouping. These groups are determined by the utilisation of the zone substation and what benefit Powerco would see from connection of generation to that particular zone substation.

⁸ Only available where the Generation Coincident Demand exceeds the Load Anytime Demand and limited to a maximum, equivalent to the connection charge.

Currently there is no overview readily available which describes DG potential for various parts of Powerco network. For the Taranaki region EECA has undertaken a 'Renewable Energy Assessment' [41] potential assessment which describes the region as follows:

- Wave energy in the thousand MW range, ignoring environmental constraints and conflicts with other maritime users.
- Approximately 300 MW of wind capacity, depending on the degree of acceptance of adverse effects.
- Less than one million litres per year of ethanol for transport fuel from grain crops currently grown in the region. About 10 million litres per year of ethanol or 40 GWh per year of electrical energy from woody biomass derived from lower-grade forestry.
- Remaining hydro potential of about 60 MW, in mini, small, and medium scale projects lying outside the Department of Conservation land or Native Forest areas, compared to the existing installed capacity of 47 MW.
- Significant potential for solar thermal hot water systems, considerably less for solar photovoltaic.

It must be commented however that no account of technology maturity and economic performance was taken into account in the EECA studies and therefore the above estimates should be severely discounted as they are unlikely to be realised in the near to medium term at least. There may be some small hydro potential but again the proximity to the network, resolving consent issues and share economics make it unlikely that the full potential will be realised.

An evaluation later in this report regarding the Network Tasman hydro case study further reinforces the view that the current legislative climate in New Zealand is not conducive to these types of investments.

Case Studies

Palmerston North City Council landfill gas generation

Palmerston North City Sewerage Treatment Plant has installed a gas-powered engine (Deutz-Germany) fed with recovered gas from the landfill (ca. 50% CH₄). The engine drives a

1.2 MVA (1 MWe) Marelli synchronous generator with automatic voltage regulation. Total efficiency is ca. 40%. Expected minimum load factor is 90%.

The project was commissioned and started generating in February 2006. The scheme is owned and operated by Energen and connects to the Powerco network at the Kairanga substation.

Since commissioning it has had problems with its gas wells being damaged due to on-going operational activities at the landfill site. The generator has therefore been running at much lower capacity than expected. There have also been problems in metering and billing and PNCC has not been charged under the new tariff system – yet.

The generator has been connected to an existing load connection of the Sewerage Treatment Plant, approximately 9.5 km from Kairanga substation, feeding into Linton-0331 GXP. Kairanga substation is not a constrained Powerco zone (A-zone) and therefore the project has not been attributed any location rebates by Powerco. Linton GXP already has a considerable amount of DG-generation (especially wind farms) and ACOT is expected to be limited (\$3.95 per kW when available).

Before installation of the distributed generator the treatment plant had an installed load capacity (at maximum demand) of 900 KVA. 12-month average load peak was expected to lower to 600 kW.

The generator is expected to have a maximum generation peak of 700 kW for the first year (potentially to increase as landfill gas production increases). Generation system Coincident

peak is expected to be 500 kW.

The scheme is charged a network connection charge of \$9.50 per kW demand per month, a TPNZ connection charge of \$0.46 per kW anytime load and a demand interconnection charge of \$1.75 per kW anytime load demand.

When in full operation the total scheme is expected to generate a minimum of 8.0 GWh p.a., previously the landfill site purchased ca. 3.2 GWh of electricity p.a., this electricity is purchased by the Palmerston North City Council based on a contract for difference.

The economics of the scheme can be broken down as shown in Table 5.4.

Based on the above numbers and assuming a tax rate of 0% (0% is assumed as councils do not pay tax) and depreciation of 20%, the project shows an internal rate of return of 77.4% over a lifetime of 20 years. The NPV of the project is \$4.1 million or \$3.0 million for a discount rate of 8 and 12%, respectively.

Based on these figures landfill gas generation seems a very attractive proposition. However, closer examination of the numbers suggest that a substantial amount of the costs have been offset, the only annual costs incurred by the plant is maintenance, connection, resource consent cost and well field tuning costs. Costs associated with personnel on site, fuel costs, etc., are not charged, one assumes that this is because these costs were already in place prior to the development of gas generation and so have not been included here, i.e. non-avoidable costs have not been allocated to the generation.

Based on the above numbers gas generation from landfill sites is potentially attractive as a

	Revenue	Cost	Total
Capital/Investment		\$ 620,000	–\$ 620,000
Annual cost		\$ 27,400	
Annual income	\$ 483,500 (@ 6c/kWh)		
Expected Rebate	\$ 23,700		
Net income			\$ 479,800
Pre tax payback			1.3 years

Table 5.4: Economics of the Palmerston North landfill gas generation scheme

fuel source for established generation. However, it should be noted that the landfill has yet to meet predicted gas flows and moreover, it could be argued from an energy utilisation perspective that greater value could be achieved from direct use of the gas as a fuel rather than converting the gas to electricity. A more extensive investigation into the plant operation and costs is required to obtain a true value of the project. An important consideration is that gas recovery from landfills is a useful way to deal with otherwise environmentally unwanted gases (obligation to collect and burn landfill methane is currently being promulgated by government).

There may also be some value in storing gas in such a way as to be able to optimise generation against pricing peaks i.e. dispatch generation in shorter high peak profiles to get higher avoidance benefits and higher energy prices. It is not clear how close to real time market conditions the operator is.

The location of the landfill site is critical in determining the value of the DG investment. Powerco has signalled, through its pricing and connection policy, that there is no particular benefit to the network company of having landfill gas generation at the Kairanga substation but the location of the fuel resource restricts the the DG investment to that particular connection point. Despite the minimal value to the network company the value to the investor was sufficient for the project to go ahead.

Wanganui Valley hydro scheme

Wanganui Valley Hydro Ltd has installed a 250 kWe hydro induction generator (Laurence Scott, 86% efficiency) with a 300 kWm Turgo turbine (Gordon Gilkes & Gilbert, England, 85%

efficiency) operating off a small storage dam with one week of storage (under no inflows conditions).

The design flow is 200 litres/sec with an effective head of 158 meters. Both import and export meters (Time-Of-Use) have been installed. The project is being finalised.

The generator will be connected to a new connection approximately 25 km from the Powerco Kai Iwi Zone Substation (Brunswick GXP). This is not a constrained Powerco zone (A-zone) and therefore hasn't been attributed any location rebates by Powerco. The nearest transmission grid node is Rangitautau East Rd.

The site is expected to have a maximum generation peak of 250 kW. The expected annual production is 1,500 MWh (a load factor of ca. 70%). Average generation Coincident with Maximum Demand is conservatively estimated to be 125 kW.

Electricity is purchased by Contact Energy at 6 c/kWh, however at some point this is expected to be established at 7 cents (plus GST).

The economics of the scheme can be broken down as shown in Table 5.5.

Based on the above numbers and assuming a tax rate of 30% and depreciation of 20% the project has an internal rate of return (IRR) of 5.3% (for a lifetime of 20 years). The NPV of the project is "\$101,000 or "\$207,000 for a discount rate of 8 and 12%, respectively. Clearly the project is unlikely to be economic on current values.

However, if the Kai Iwi generator were to be placed in one of Powerco's 'constrained zones'

	Revenue	Cost	Total
Capital/Investment		\$ 608,000	-\$ 608,000
Annual cost		\$ 40,600	
Annual income	\$ 90,000 (@ 6c/kWh)		
Expected Rebate	\$ 5,900		
Net income			\$ 55,300
Pre tax payback			11.0 years

Table 5.5: Economics of the Wanganui Valley hydro scheme

the rebates would be more significant, i.e. in the Whitianga – eastern region – increased rebates would decrease the payback period to 8.4 years and offer an IRR of 8.5%. Powerco's connection and pricing policy illustrates the minimal value of this investment in its current location but the generation resources are tied to a specific location, limiting the ability of the investor to choose a connection location.

Once again costs included in this analysis are specific to the site. Other costs associated with the project such as personnel appear to be covered by the Wanganui Valley Hydro Ltd. as part of their business costs. A fuller economic analysis is required before a true IRR can be established for the life of this DG-investment.

Twenty-five km is very remote from the network and therefore this is not a typical example of an economic DG application. Remote Area Power Supplies for domestic supply can become attractive alternatives to network connection for distances as close as 2 km. The length of the network connection is likely to be the primary constraint on economics. DG would more typically be used as a solution to avoid the need for such a connection rather than create the need.

Conclusions

The above two case studies present an interesting dilemma. Powerco's pricing signals are intended to be supportive of DG investment in its Eastern Region as this is a region of high growth and is also increasingly constrained because of summer (holiday) demand profiles. Whilst a location rebate is provided for the region is it sufficient to attract new investment?

If the Wanganui Valley hydro scheme was located in the constrained eastern region the rebate received (\$16,608 per year) returns an IRR of 8.5% over 20 years. To achieve the same IRR, but from the Wanganui location would require a yearly rebate of \$23,600.

DG is suited to locations where the network is located nearby and where connections assets already exist with sufficient capacity. The highest value locations to both network owner and investor as those with network constraints but the landfill gas generation case study

illustrates that the value to the investor can be sufficient to progress with installation in unconstrained locations if the location and resources allow.

Maximum value is created if plant is operated at peak output during times of system load peak. This is not always an energy issue, as three peaks need to be considered:

1. Network local load peaks when there is a network constraint.
2. GXP system level profile peaks relative to transmission constraint signals in the Transmission Pricing methodology.
3. Energy Market spot price peaks.

Location, contracts, and circumstance will determine which of these creates the highest value for the generation owner. For small projects the complexity and unpredictability of these peak markets seems to work as a deterrent to actively manage opportunities.

Existing parties (retailers, lines companies) do not seem to offer support/products in this area either. Ideally generation operators need to be sent a dispatch signal by network operators if they are to respond effectively.

We note that recently some aggregators have entered the market and are actively seeking such opportunities.

Orion Case Study

General Parameters of Case Study

These case studies are line company initiated DG investments targeting line company issues. Development of the Orion network to meet future growth in demand is capital intensive and is coming under increasingly detailed scrutiny [42]. Investment in DG is part of Orion's response to this increasing demand. DG development is driven by perceived financial efficiency and Orion's assessment of longer-term investment risks related to network expansion.

Orion thus describes its investment in DG as a short-term solution to provide adequate capacity to meet peak requirements. However, transmission is also very constrained into Christchurch. Orion considers transmission security of supply an issue for it to have a

management involvement in. It also acts to minimise transmission cost in the interests of its consumers rather than adopting a pass-through stance.

Description of Line Company

Orion is a Canterbury based energy distribution company. It owns and operates the third largest electricity networks in the country serving 180,000 consumers. The company is owned by the Christchurch City Council (89.3%) and the Selwyn District Council (10.7%).

The company states that its objective of its AMP is to “provide, maintain and operate Orion’s electricity network while meeting agreed levels of service, quality, safety and performance”.

Orion’s owners have a close involvement in regional economic development. Orion is the provider of a key infrastructure servicing a well-defined regional economy. This is reflected in the Canterbury Regional Energy Strategy, which Orion has had a key input role in developing.

Description of Network

Orion’s electricity network is located in central Canterbury between the Waimakariri to Rakaia Rivers, stretching from the coast to Arthur’s Pass. This region encompasses a variety of terrain including urban areas (Christchurch city), rural farming regions and isolated high country. However, the network has a strongly urban focus.

The specifics of the Orion network can be summarised shown in Table 5.6.

Orion has 375 major customer connections (defined as having a maximum electricity demand greater than 250 kVA) [43]. While this

is only 0.2% of its customers these consumers consume 25% of total electricity.

Currently Orion is reviewing its Security of Supply standard to ensure an appropriate economic balance between investment in security of supply and all other factors leading to reliability performance. They expect the new standard to better reflect the level of security customers require based on probabilistic analysis of customer operations. N-1 security threshold limits are intended to be relaxed from 10 MW to 15 MW, this decrease in substation reliability is not anticipated to have a significant impact on overall network reliability.

Orion appears as an industry leader in terms of its security standards and delivery. Much broader economic issues are addressed in its security management than one would expect from a purely commercial minimum compliance orientated approach.

The demands on Orion’s network continue to grow due to urban growth and the development of high energy intensity practices in rural areas (i.e dairy). Demand is growing at around 1% per annum, Orion projections for peak demand are for growth at 1.5% per annum over the next 10 years.

Network Issues

Capacity constraints due to peak demand are the major driver for network investment in the Orion region. As explained in the Canterbury Regional Energy Forum report on energy security issues in Canterbury [38], most networks within the Canterbury and South Canterbury region are seeing annual energy (GWh) growth rates between 2 and 3% and peak demand growth rates of between 1% and

Consumer connections	180,500
Network area	8,000 km ²
Lines and Cables	13,748 km
Number of GXPs	9
Zone Substations	50
Total electricity	3,255 GWH
Peak demand	592 MW
Load factor	62.9 %
Connection density	6 - 30 consumers per km for rural and urban network respectively

Table 5.6: Network Characteristics for Orion (Source: Orion AMP)

2%. Orion, via a practice of peak shifting its load, is able to limit peak demand growth rate being at the lower end (1.3% averaged over 20 years).

Maximum peak demand is a hard quantity to predict as it is very dependant on the weather, which in the Canterbury/South Canterbury region can be quite volatile. This volatility is present in both summer, from irrigation (a dry year results in large irrigation load) and in winter (from heating).

It should be cautioned that when load is added gradually over several years of moderate conditions an extreme event can result in very high previously unseen peak demand. If the system is running very close to its limit then unexpected cold weather can result in capacity constraints that were not planned for. Many of the urban GXP's in Orion's network are forecast to run into firm capacity constraints within the next 5 to 10 years. Islington and Bromley are the worst affected, with potential problems also surfacing at Addington, Springston and Hororata. Some projects are already planned to relieve or partially relieve some of these constraints.

Furthermore, demand growth in Canterbury and north in Nelson/Marlborough is putting significant strain on the transmission system running from the southern generators up the island. Transpower has recently commissioned another circuit north of Christchurch to Kikiwa but capacity on the lines running into Christchurch is already stretched and will continue to worsen. Transpower is looking at a number of alternative solutions to this issue. They are proposing a number of small capacity increments using improved bussing and transformer ratings/ capacity in locations such as Islington, Bromley and Ashburton and series compensation of the transmission circuits supplying Canterbury. These projects may culminate in a new transmission circuit from the southern generator region into Christchurch in the future.

As a consequence Orion has an active policy of encouraging measures, such as DG, so as to relieve peak demand duration. For example, take Figure 4.6 which in the words of the Orion AMP [42] "shows that in the year ending March 2006 our load on Transpower exceeded 583MW for about 8 half hours, even though the

highest net demand was about 591MW. In the 2002 winter, peaking generation of 30MW would only have needed to operate for about 4 hours to reduce the urban network maximum demand by about 30MW. In the 2005 winter, generation of 10MW operating for about 4 hours could have reduced our urban maximum demand by about 8MW".

The ability to use DG to meet peak demand requirements eases the supply requirement across the distribution network and reduces the need to import power into the network to meet these demands.

The importance of 'peak management' and diversity of supply to Orion's investment strategy is also reflected in their pricing policy. Orion's customer pricing is mainly focused at peak pricing in order to reduce peak demand and thereby stimulate efficient use of the network and reduce the need for (future) new investments in line capacity. Two main customers are identified.

General Customer Pricing

Orion does not have any fixed connection charges, but assigns all its charges to variable (kWh) and peak charges (kW). The 'capacity price' component is simply a price for the amount of electricity used and is charged at differing rates depending on the 'zone', month and time of day. Charges are less at night generally to encourage retailers, and in turn households and businesses, to use electricity at night-time when the network is not so heavily loaded. Orion reports that during a peak period, a customer's electricity use effectively costs around 85 cents/kWh. This compares to a cost of around 0.5-4.5 cents/kWh during non-peak period times.

Major customer pricing

To qualify as a major customer in Orion territory, a business needs to have a maximum electricity demand of at least 250kVA. Pricing for major customer's has four components:

- a customer-specific charge for the equipment provided by Orion that is dedicated to delivering their electricity (e.g. transformers),
- a fixed per annum price for their connection(s),

- a 'control period demand' price of \$66.40 (excl GST) per kVA of demand during control periods, and
- an 'assessed capacity' price of \$24.40 (excl GST) per kVA of their assessed capacity.

The control period demand charge and the assessed capacity charge make up the majority of the annual distribution costs to major customers. The control period demand charge is based on the average demand during peak control periods and the assessed capacity is calculated as the average peak demand in the previous 12 months (irrespective of whether they occurred during network peaks). This provides major customers with some cost certainty and Orion with some revenue certainty.

DG Profile within the Network

Orion owns and runs one generator permanently located within the network, three generators providing emergency backup for the operational control centre at Manchester St and

two mobile generators (specifics listed in Table 5.7). The permanent generator is a 800kVA diesel generator that is installed at Lyttelton and utilised for peak load shedding and providing a 'lifeline' electricity supply to the Lyttelton area in the event of the failure of the main feeder supplying the area. This generator can be shifted to another location in the event of an emergency if required.

The two truck mounted generators are used for restoring power at a distribution substation during a fault or some planned works.

Recently Orion gained resource consent to install a 10 MW diesel generating set on sites at Bromley and Belfast. (In large permanent installations gas engines could also be considered. Ideally these would be located where there is excess capacity in the gas supply infrastructure and/or an opportunity to use the available heat energy arising from combustion).

Proceeding with either of these installations was subject to satisfactory contractual arrange-

Generator listing (owned by Orion)		
Location	Generator ratings kVA	kW
Simeon substation (Lyttelton)	800	640
Truck mounted	440	352
Truck mounted	350	280
Orion car park	110	88
Manchester St car park (basement)	55	44
Armagh district substation	30	24
Total generating capacity	1,785	1,428

Table 5.7: Capacities of generators owned by Orion New Zealand Ltd

	Diesel	Landfill gas	Wind	PV & fuel cell	Totals
	Units (kVA)	Units (kVA)	Units (kVA)	Units (kVA)	Units (kVA)
Load substitute	81 (15,490)	1 (200)	–	2 (2.65)	84 (15,693)
Expect export	51 (14,065)	–	2 (500)	–	53 (14,565)
Totals	132 (29,555)	1 (200)	2 (500)	2 (2.65)	137 (30,258)

Table 5.8: Embedded Generation Connected to Orion's Network (Source: Orion New Zealand Ltd)

ments with the Electricity Commission being negotiated. The Commission has advised, however, that it does not wish to contract for any additional capacity and consequently this project is now on hold. Orion may instead be able to develop sufficient installed DG contract with Transpower or seek to be recognised as an alternative solution proponent with respect to the Grid Upgrade Plan process.

Other Distributed Generation Includes (details in Table 5.8):

- 2 (small) wind farms (Gebbies Pass & E3 Energy).
- Many backup diesel gensets running in peak-opping mode with some export potential.
- Some cogen installations, of which 6 have a generating capacity of greater than 1 MW.

There are no small-scale hydro power installations in the Orion network.

The same pricing signals also encourages consumers to take other demand side actions such as using the storage of freezers, changing processing times, etc.

Previous CAE studies have clearly demonstrated that DG has the potential to reduce the need to extend network capacity and may be more economic in certain situations than other options. However, DG is also important for Orion as its 'peak load' forecast assumes that an additional 2 MW per annum of peak distribution generation will be installed.

The economic basis for this is uncertain given the EC refusal to contract for additional capacity, but it would appear that Orion is committed to bringing on-line DG to ensure the robustness of its network, both in terms of network capacity and robustness to faults. This requires that the DG is able to come on-line when necessary, i.e. its fuel must be able to be stored or be stable and reliable, this means that renewables may not be able to meet Orion's requirements [42].

If gensets were justified on the basis of being a security solution as distinct from an energy trading use the Commerce Commission dispensation for exceeding non-renewable generation limits should be achievable.

In terms of Orion's own security requirements DG can provide an alternative lower cost (and therefore more affordable higher security) solution to conventional lines solutions of building extra interconnections and installing redundant transformers. A mobile genset located at a zone sub has more flexibility and can deliver security further out into the network. When line solutions are applied to security they aren't expected to meet the same investment criteria.

Orion DG policy

Orion's DG policy [44] is an extension of its network pricing policy in that it tries to stimulate reduction of peak load on networks, in this case by rewarding generation in peak periods. As stated in its information "embedded generation that reliably generates during peak demand times can provide an economical alternative to electricity delivery, enhancing security of supply and service quality".

Orion contracts export credits with DG generators who can commit to certain levels of output during peak or control periods. The credits do not represent the purchase of electricity, and exporting customers are able to separately negotiate to sell exported energy, usually to their electricity retailer. In 2006 Orion also introduced a policy of generation credits that rewards DG-generators (also those that do not export) for generating in Orion's control periods. No commitment to generation levels is required.

Export credits

This standardised arrangement applies to connections where the combined output rating of the generation at the connection does not exceed 1,000 kVA (Orion considers the terms and level of credits on an individual basis for connections with generation capacity in excess of 1,000 kVA). Export credits were first introduced and have been provided since 1 May 1995. Over time, Orion has developed these arrangements to better reflect its network needs. Recently (2006) export credits have been reduced to reflect their 'reduced contribution to security level compared with providing additional delivery capacity'. There is thus likely to be an optimal level at which further additional capacity will be less economically

efficient than network reinforcement.

A. Requirements

To be eligible for export credits, embedded generation must meet a number of prior requirements. In summary, each customer must:

1. Apply to Orion for approval – where Orion assesses that the addition of the generator will beneficially supplement network capacity, operating characteristics (e.g. power factor) and/or enhance supply security (even in the longer term, considering the possible connection of further embedded generation). Orion will generally approve the generation for export credits.
2. Commit to the specified level of generation – the customer must agree to use reasonable endeavours to generate and export at the levels and during the periods indicated in the application for approval. Orion may withhold payment if it establishes that this commitment has not been met. With reasonable notice, customers may withdraw from this arrangement at any time, and may subsequently re-apply for export credits. Customers who withdraw during a peak period or control period season and subsequently re-apply may not be accepted on Orion's standard terms.
3. Have appropriate metering – Orion's export credits are based on measured export volumes during specific periods. Customers wishing to take advantage of Orion's credits must ensure that appropriate metering is in place to record the creditable quantities required for the calculation of credits.
4. Meet Orion's requirements – connections must comply with Orion's Network code and connections with embedded generation must also comply with Orion's design standard requirements for embedded generation [45].
5. Meet statutory and regulatory requirements – there are a number of statutory and regulatory requirements relating to electrical safety and reporting of information.

B DG-Categories

For the purpose of applying credits, connections with embedded generation are categorised based on the combined available output capacity of the installed generators at the connection. In most cases this will be the sum

of the generator nameplate kVA ratings, but this may be de-rated where the power source is limited. The export credit categories are:

- Small - 0 to 5 kVA
- Medium - 5 to 30 kVA
- Large - 30 to 1,000 kVA

C Creditable periods

The credit basis for each export category varies in terms of incidence, duration and payment level. For small and medium size generators, the credit is based on export that occurs during Orion's peak period. In essence peak periods occur when Orion is shedding residential hot-water heating load in order to limit the maximum load on the network - during winter in the mainly urban zone A, and during summer in rural zone B⁹.

For large generators, the credit is based on the average export that occurs during Orion's control period. These periods are basically defined as the periods when Orion activates its 'ripple control' signals to manage peak demand. The total annual length of the control period varies from 20 to 120 hours.

Generation credits

In 2006 Orion also introduced credits to customers that generate electricity when signalled by Orion (without necessarily exporting). This arrangement provides the opportunity for Orion to enhance security of supply during constraints and reduce the duration of residential hot-water shedding during times of peak loading. Generation credits are separate from, and available in addition to, the export credits (as detailed above). Unlike the export credits, this credit is based on the amount of electricity generated, rather than the amount exported, recognising that generation lowers the load on Orion's network (regardless of whether the electricity is used within the connection or by other connections).

Subject to the requirements below, Orion's

⁹ Note that under the proposed new Transpower pricing regime, peak demand would not be charged per GXP anymore, but averaged per region. This would mean that the summer peaks in the rural zoned (mainly irrigation) will most likely be averaged out by the urban peaks. Orion will most likely change its connection pricing rebate policies accordingly.

generation credits are available in respect of all connections where the combined output rating of the generation is between 30 kVA and 1,000 kVA. Orion will consider making the credit available to connections with more generation than this on a case-by-case basis, considering the location within the network and the magnitude of the load change. In these cases Orion may offer a lower price or specify a maximum generation setting. It is not economic for Orion to process payments for generation of less than 30 kVA.

A. Requirements

Requirements are generally the same as those described above, Orion must approve the generation as being eligible for generation credits. Orion's aim is to lower the load on the overall network and Orion will approve generation that assists with this aim. Unlike export credits, customers are not required to commit to any set level of generation. With the aim of lowering loading levels on the overall network, the diversity in generation response is spread over a larger number of contributors (this generation is not intended for localised security of supply or to reduce capital expenditure on network capacity). Customers may elect not to run for various reasons such as high diesel prices, maintenance constraints, exceeding the running hours allowed in the terms of their operating consent, or because they cannot run at certain times of day or days of the week. Orion will not generally approve this credit for passive generation, such as wind turbines or solar PV, which are not able to switch on when required.

B Creditable periods

Credits are provided for generation only during Orion's ripple signalled generation period. Generation periods are instigated manually by Orion, when it is beneficial to lower the overall load on the network, subject to the following:

- Generation periods only relate to *load management* (in response to peaks or constraint situations, or to test the response of the arrangement). Generally, to comply with resource consents, generation periods are not initiated for other reasons (such as in response to energy shortages).
- Each generation period runs for a minimum of 30 minutes, but is not limited to any

maximum duration. In extended generation periods, customers may elect to cease generation prior to the end of the generation period.

- There is no minimum or maximum total duration of accumulated generation period each year, although Orion expects to test the arrangement each year providing at least 30 minutes of generation period.
- Generation periods can occur at any time of day, any day of the year, with no warning.

Orion aims to minimise any period of overlap between generation periods and major customer control periods. On occasions when overlap does occur, the customer may simultaneously benefit from the generation credit, a reduced contribution to control period demand, and possibly the export credit.

Connection and rebate policies are reviewed annually. Orion reserves the right to alter the policies and does not make long-term commitments in respect of its DG-policies.

Very large generation

The standard export and generation credits do not normally apply for connections with combined generation capacity in excess of 1,000 kVA. The benefits of embedded generation in relation to electricity delivery are not as clear when a large contribution is applied at a single point in the network, even if this is only offsetting a customer's existing load.

Orion's restrictions on the standard basis for export and generation credits are intended to allow Orion to maximise the benefit from this group of customers.

Orion individually assesses the benefits provided by each opportunity, and provides customised credits that reflect these benefits. In some cases the standard credits may be offered, but in other cases a reduced credit or additional terms and conditions are offered. Orion may also limit the term of the credits to an appropriate number of years to reflect the benefit derived from embedded generation. When assessing the benefits provided by very large generation, Orion considers:

- planned capital expenditure which might be deferred
- the actual expected reduction in transmis-

sion expenses

- the level of supply security provided by the generation
- the interaction with other generation in the area, and
- the availability of generation during capacity shortages (other than at peak times, for example, during planned maintenance).

Case Studies

Chateau-on-the-Park – Diesel

The 'Chateau on the Park' hotel in Christchurch is a 'major customer' on Orion's Network; therefore its distribution costs are set by peak demand. In 2001 it decided to install a 375 KVA (300 kWe) diesel stand-by set to secure its electricity supply and lower its peak demand (maximum demand was around 500 kWe before installation) and thereby distribution costs. Since 2006 it has also participated in Orion's generation credits scheme, when possible generating on Orion's signal in control periods. For this purpose the generator is equipped with a separate meter at the generator. The hotel does not export electricity.

The project was commissioned in 2002. Total investment was around NZ\$150,000, which paid itself back in ca. 3 years according to Orion.

The generator is owned by Abacus Pty Ltd and operated by 'Chateau on the Park'; it is connected to the network at the main MEN switchboard. As it is connected behind the hotel's existing connection point it does not attract any separate connection charges. Its main influence is lowering the monthly (average Control Period Demand) and assessed (annual average peak) demand for transmission and distribution charges.

The Control Period Demand is calculated as the average demand in Orion's Control Periods (20 – 120 hours per year). The assessed demand peak is calculated according to the Transpower methodology, i.e. the average of the 12 highest demand peaks in the last 12 months.

On the bases of the information supplied the economics of the scheme can be broken down as shown in Table 5.9.

Based on the above numbers and assuming a tax rate of 30% and depreciation of 20% the project has an internal rate of return (IRR) of 10.9% (for a lifetime of 20 years). The NPV of the project is \$30,000 or "\$10,000 for a discount rate of 8 and 12%, respectively. However these numbers may not tell the full story as Orion report on their website that "the Chateau on the Park (a local hotel) has invested over \$150,000 in an energy management system and a diesel generator. As a result of our pricing, its investment in this technology was paid back in around three years through savings in ongoing electricity purchase costs".

It is hard to pinpoint what is the reason behind the variation between our and Orion's payback estimates. The reason may be that the accounting benefits applied in our analysis only considered tangible benefits, consideration was not given to other economic cost benefits driving the owner's value decision (such as the loss of business if the supply is interrupted). This generator was not installed to produce energy economically for sale, the generator is an investment in risk management and in an ideal world it would never be needed. Our analysis is not assigning any value to risk management; in its analysis Orion may well have assigned such a value. A minimum value for risk management would be the savings associated with the next cheapest option to

	Revenue	Cost	Total
Capital/Investment		\$ 154,000	–\$ 154,000
Annual cost		\$ 12,600	
Load reduction	\$ 34,700		
Net income			\$ 22,100
Pre tax payback			7.0 years

Table 5.9: Economics of the Chateau-on-the-Park diesel

achieve the same security level. This is a point that should be noted for all cases in this report; the analysis in this report is treating DG as if it is a generation only proposal. In some cases, such as this one, the benefits calculated are only a bonus; they are not the primary reason behind the installation of DG.

Southbridge wind generator

Energy³ owns and operates a single 100 kW wind turbine at Southbridge in the Orion network. The turbine is a second hand Tellus T1995. Average wind speed at the site is 6.5 m/s and the expected annual load factor is ca. 25% with an expected generation capacity of 210,000 kWh p.a. The project was connected and commissioned in 2003 at a new connection, but close to an existing 11kV feeder.

RMA-issues were of little concern in this project. The council approved a non-notified consent and the whole process took 3 to 4 weeks. Total consenting costs were in the order of NZ\$6,000 for landscape consultants, council fees and documentation and legal work

Cost for the new connection (but at short distance from an existing 11 kV feeder) was ca. NZ\$17,000, the nearest transmission grid node is at Hororata.

Annual connection costs total around NZ\$500 p.a. Export credits are likely to be low (average 25 kW export) as wind generation can't be controlled to generate in peak periods. This is estimated at NZ\$1,500 p.a.

Meridian purchases the electricity generated by the turbine at a price of approximately 7 c/kWh.

The economics of the scheme can be broken down as shown in Table 5.10.

Based on the above numbers and assuming a tax rate of 30% and depreciation of 20% the project shows an internal rate of return of 5.2% over a lifetime of 20 years. The NPV of the project is "\$24,000 or "\$48,000 for a discount rate of 8 and 12%, respectively.

It is interesting to note that the turbine was purchased second hand from Europe. According to the Energy³ website [46], the turbine has a lifespan of 25 years of which 15+ years are still available. The company believes that using second hand wind turbines (5-10 years of age) from Europe will provide a cost-benefit, improving the commercial attractiveness of developing small wind farms (5 turbines operational plus 1 spare) to produce 2-4 MW of electricity. The extra age of the turbines will mean that additional maintenance will probably be required; Energy³ has budgeted for 1 turbine to be reconditioned every third year (based on a 5 turbine site).

The Southbridge turbine has an average yearly maintenance allowance of NZ\$2,000 a year. Despite this low maintenance cost the economics are marginal at best. While this project was a pilot study of 1 turbine to determine the practical feasibility of distributed wind generation, the optimal size of the project, according to Energy³ [46], would be to have 5 turbines operating with wind speeds of 7-8m/sec. The economics of such a project would improve, but whether it would be commercially viable is uncertain.

Also of note is that this site has a very low quality wind resource (6.5m/s, 25% availability). The same installation in a better location would achieve a positive NPV (7.5m/s, 30% availability). It is also likely that slight larger and taller turbines (500-1000 kW) would achieve better viability.

	Revenue	Cost	Total
Capital/Investment		\$ 140,000	-\$ 140,000
Annual cost		\$ 4,000	
Annual income	\$ 14,700@ 7c/kWh		
Expected Rebate	\$ 1,500		
Net income			\$ 12,600
Pre tax payback			11.1 years

Table 5.10: Economics of Southbridge wind generator

A key conclusion from this installation is that smaller second-hand plants have a reduced investment requirement and lower risks. Therefore there will be savings associated with the project, for example a lower level of wind monitoring will be required, and lower quality wind resources could be utilised. This increases the likelihood of locating the site very close to the network and the network having sufficient connection capacity, thereby minimising costs.

CCC landfill gas cogeneration engine at QEII sports complex

The Christchurch City Council (CCC) recently closed the Burwood landfill and is now converting it into a green space. To deal with a concerns of local residents with regards to smells that may be associated with landfill gas (LFG) a system of wells and associated pipe work was installed and the collected gas flared. This system became operational in May 2004. A subsequent study was performed to gauge the economic viability of installing additional wells (to increase gas volumes), processing the gas and transporting it 4 km by underground piping into QEII for use in the sport complex's boilers. As part of the concept study the inclusion of a base load cogeneration system was raised, and following assessment was included in the project.

The cogeneration engine is used to provide both electricity and heat. It produces enough electricity to meet the base load requirement of the complex, which results in an annual saving of \$215,000. As all the electricity produced by the plant is used within the complex, electricity is not sold back to the network. Heat produced by the cogeneration engine is used to heat the QEII swimming pool. The engine produces electricity at 30% efficiency; however by utilising the excess heat

produced a total efficiency of 60% is achieved.

The total project (methane capturing wells, associated pipelines and the co-generation plant) cost \$4.2 million to install and is reported to have a 4 year payback period [47]. The project was viable as the CCC obtained Kyoto Protocol 'Carbon Credits' for the destruction of the methane content of the LFG. A tender for Carbon Credits was submitted to the Ministry for the Environment in Oct 2004, which was successful as part of the government's "Project to Reduce Emissions Programme". The government awarded the council 200,000 carbon credits for the capture and transport of methane gas from the landfill. In September 2006, CCC sold its carbon credits to a single, overseas, private sector buyer for \$3 million over five years (2008-2012)³⁵. Further savings were achieved by using the landfill gas to heat the complex swimming pool. Traditionally, heating has been achieved using liquefied petroleum gas (LPG); in 2004 the complex used around 1.5 million litres of LPG at a cost of \$550,000 [48].

The economics specific to the co-generation engine is shown in Table 5.11.

Based on the above numbers and assuming a tax rate of 0% (0% is assumed as councils do not pay tax) and depreciation of 20% the project results in an internal rate of return (IRR) of 18.1% (based over 20 years). The NPV of the project is \$467,000 or \$156,000 for a discount rate of 8 and 12%, respectively.

The cogeneration plant, on its own, appears worthwhile. When consideration is given to savings made through the reduction of LPG use and the revenue gained from the sale of carbon credits the operation as a whole looks very attractive. As stated early, the council

	Revenue	Cost	Total
Capital/Investment		\$ 930,000	-\$ 930,000
Annual cost		\$ 40,000	
Annual income	\$ 215,000		
Net income			\$ 175,000
Pre tax payback	Excl. LPG savings & carbon credits		5.3 years

Table 5.11: Economics of CCC gas cogeneration engine

reported that the project, has a whole, had a payback of 4 years.

Conclusions

The strategic direction adopted by Orion to encourage DG connections within its network has encouraged DG penetration. However, its stated aim to bring on-line 2MW of DG per year to ease peak demands on its network (and to reduce the need to upgrade network capacity) suggests that its price scheme may need future adjustment to encourage a greater uptake.

The connection and pricing policy developed by Orion has affected the locations and types of technology used in DG investments. The policies reward controllable or firm generation that Orion can use for peak load reduction. This has influenced the choice of technology used for DG with investors turning to gas or diesel generation rather than intermittent wind or solar/PV so as to maximise their income from generation and/or export credits. The interaction between Orion's pricing policy and investment technology choice is a good example of well designed policy maximising value to both investor and network company.

The economics for DG presented here are more positive than the case studies from the Powerco network. Whilst the numbers behind the wind farm were poor, the other two case studies report good returns, with both operators reporting a payback period of less than 5 years.

The wind farm offers little benefits to Orion as it is a robust network looking to reduce peak demands rather than making the network more secure. As wind production cannot be pre-determined its generation does not assist Orion's network priorities. This issue could potentially be overcome by selecting slightly better resource sites, having some diversity and using other generation such as diesel gensets already installed to firm the wind generation.

There is also another obvious wind application that is often overlooked. That is using wind directly to pump and store water instead of electricity. Wind pumping and generation has many synergies with irrigation.

The Chateau on the Park generator is an example of a system that can be timed to meet the needs of the network and so is used by the hotel to reduce its load. The hotel reports that the generator paid itself off after 3 years of operation, but this is not supported by the study team analysis. The discrepancy most likely lies in that the accounting benefits applied to the study analysis only considered tangible benefits, and excluded other indirect benefits arising from loss prevention.

Gas cogeneration at QEII returned positive values with an internal rate of return around 10%. The system reduces the base load from the QEII complex. The use of landfill gas as an alternative fuel source to LPG and the revenue that can be gained from carbon credits results in CCC gas utilisation project, of which the cogeneration plant is a part of, having a payback period of 4 years.

The numbers for this project suggests that savings obtained by reducing QEII's electricity use was a nice project perk; the driving force behind the work was the council's desire to reduce its LPG costs and to take advantage of potential carbon savings. Having a host heat load was also important.

Network Tasman Case Study

General Parameters of Case Study

This case study is an example of consumer DG investment encouraged by the lines company to solve line issues. Network Tasman sees DG as a way of reducing network losses, and the potential for reduced GXP demand based charges through cooperative action [49].

Description of Line Company

Network Tasman distributes electricity across the wider Nelson and Tasman areas and is owned by the Network Tasman Trust on behalf of its customers. The distribution network is relatively small compared to Powerco and Orion, with only 33,000 (approx.) consumer connections but typical in size and profile for most NZ regional line companies.

The company's mission statement is "to own and operate efficient, reliable and safe electricity networks and other complimentary busi-

nesses while increasing consumer value” [49].

Description of Network

Network Tasman distribution network is based in the north west of the South Island (Figure 4-7) encompassing the wider Nelson region and the Tasman area. It runs from the coast in-land skirting the major ranges in the area. The company supplies a mixture of high connection density urban areas and low connection density rural areas. Its does not own the distribution network serving Nelson city

The specifics of the network can be summarised as shown in Table 5.12.

Network security is superior within the urban industrial and commercial areas where load density and interconnection is higher. The urban areas have a high level or reliability relative to the rural networks. This is consistent with Network Tasman’s security policy.

In the foreseeable future (10 years) Network Tasman predicts a steady state increase in both its energy consumption and peak demand with grow at a rate of 18 GWh and 3 MW per annum, respectively. This means that percentage growth is projected to decline over these years. The Tasman region has one of the highest population growth rates in New Zealand and as a result Network Tasman is currently observing demand for new connections, followed by demands for greater capacity. High growth means that the Network Tasman can only plan with a degree of confidence for up to five years. DG security and capacity options that facilitate incremental and sustainable upgrade paths are therefore desirable.

Network Issues

The nature of development in the region means that Network Tasman cannot predict with any degree of accuracy long-term trends across its distribution network. Consumer demographics are changing significantly.

Currently Network Tasman expects that:

- Continued residential growth over the next ten years, especially in costal zones and areas nearer forestry regions.
- A move away from combustion heating to electricity heating as the Tasman region attempts to improve air quality in winter.
- Industrial growth around Tahuna and Richmond, mainly light manufacturing, seafood processing and packaging, fruit packaging, cold storage and timber processing.
- Conversion of farmland and rural blocks into lifestyle blocks around Nelson and in Moutere and the Waimea Plains and Golden Bay
- Dairy development in the Maruia Valley and Tapawerea area. Both areas are remote from an electricity supply view point.

Currently no sections of the network has experienced lost of load rendering network assets stranded, however some regions of the network are uneconomic. Further development in remote areas will put further strain on the network. Development of DG will be of assistance during this period of growth, potentially reducing demand, and hence Transpower charges; DG development would be more advantageous in remote regions where it can increase supply security by providing an electricity source should parts of the network become isolated due to network failure

Consumer connections	34,400
Network area	10,800 km ²
Lines and Cables	3,265 km
Number of GXPs	5
Zone Substations	10
Total electricity	701 GWh
Peak demand	133 MW
Load factor	64.5 %
Connection density	—

Table 5.12: Network Tasman distribution network details

elsewhere.

DG Profile within the Network

Tasman Network's DG policy is as given in its AMP as follows.

Network Tasman has an open access policy and welcomes the connection of all forms of distributed generation on its network. The benefits of reduced network losses, and the potential for reduced GXP demand based charges through cooperative operation are well recognised. There are three examples of distributed generation operating within the NTL network at present. Prior to the connection of new distributed generation, it is necessary for studies of the operating conditions of the new generator at the point of connection with the distribution network to be completed. These studies identify issues that may affect existing network assets or other users of the network. Examples include asset overload or introduced effects such as voltage rise or voltage disturbance creating interference with other connected consumers supplies.

Operation of the generating plant under network fault conditions and provision of means to isolate the generation during times of network maintenance are also required to be understood and managed. Deployment of NTL operated local generation is considered as an alternative to incremental distribution asset investment as a part of the network development planning process. This is an option particularly applicable when seasonal peak loads occur such as in holiday areas or seasonal/temporary loads such as crop harvesting.

Additional communication with the company¹⁰ determined that the cost of extending the network to cope with any installed DG is passed on to the developer. The exception being when the DG offsets already intended network development; an example would be when the DG removes the need for expected network development due to load growth. The costs incurred by a developer may be rebated if other DG applications take advantage of network development (in these cases the

rebate would be charged to the new developer).

Typically small DG installations (0-10kW) can be accommodated on the network with minimal fuss, however bigger installations (50-200kW) will require an investigation to determine the network investment that would be required to meet DG generation capacity.

Network Tasman, like all networks is not permitted to purchase electricity from DG owners. It passes on to the DG operator the avoided cost of transmission. There are no long-term contracts for avoided transmission cost. Nor has DG been used as an alternative to transmission upgrade, which is surprising given the growth and transmission issues in the region.

There are three examples of DG operations within the Network Tasman network at present. They are privately owned hydro schemes located within the Golden Bay and Motueka GXP regions (Brooklyn, 250 kW; Onekaka, 900 kW; Pupu Valley, 250 kW). Network Tasman also owns and operates one relocatable 1 MW diesel generator.⁴⁶

Case Study

Onekaka mini hydro scheme

The Onekaka hydro scheme is owned by Onekaka Energy and operated by Bryan Leyland. It is based on an abandoned scheme that supplied the old ironworks in Golden Bay, at the top of the South Island. The project uses the original dam and second-hand equipment to reduce costs. The 2 unit 940 kW hydroelectric scheme was built and commissioned in October 2003 (it was realised in hindsight that a new 800 kW vertical Pelton wheel turbine and supporting penstocks above ground would have been cheaper than the reconditioned old plant). The scheme is connected to the network at Motupipi, which is also the location of the closest GXP.

The station is unattended and is monitored and controlled by cell phone text messaging. Design flow is 630 litres/sec with an effective head of 210 metres. The efficiency of the new runner in one of the turbines is 89.2%, the original efficiency was probably about 80%. The installation has half-hourly (ToU) metering

¹⁰ Personal communication with Murray Hendrickson, Network Tasman

of active and reactive power generation.

At the dam there was 120 W solar cell to supply the radio and PLC but this could not supply the control circuits with a standing load of 6 W. Overall it has been a reliable system, but has required some fine-tuning.

The initial 11 kV grid connection used was not adequate, mainly due to voltage swings caused on the local 11 kV network. The installation HV connection therefore had to be up rated to use a 33 kV feeder (with assumed extra costs). The initial maximum output of 400 kW at 11 kV was able to be increased up to the rated 940 kW at 33 kV.

The Resource Management Act and other regulatory requirements caused problems and delays. Overall, these probably added \$300,000 to the cost of the scheme. It is not obvious that there was any environmental benefit from this. Much of the cost was for consultant's reports and legal fees. The consultant's reports showed that, as would be expected, floods were the major environmental effect on the river upstream and downstream of the scheme.

The average annual energy output is 3.6 GWh which is sold in to the electricity market at spot price. Charges by the network are \$15 per day for administration and transformer supply; in return Network Tasman offers a rebate of \$11 per day for avoidance of transmission interconnection charges. In addition there is a charge of 3% of gross income as water rent to DOC.

The economics of the scheme can be broken down as shown in Table 5.13.

Based on the above numbers and assuming a tax rate of 30% and a depreciation of 20% an

internal rate of return rate of 2.3% is obtained (for a lifetime of 20 years). The NPV of the project is "\$724,000 or "\$1,020,000 for a discount rate of 8 and 12%, respectively.

It is clear from the above breakdown that this scheme is not economically viable and that with a payback period of 15 years it is at best a marginal investment and at worst a poor one.

Conclusion

This case study shows that the economics of small scale hydro schemes is limited by location. Leyland, the operator of this scheme, concludes in his paper [50] that such projects are unlikely to be economic due to the regulatory and legal environment in New Zealand. He goes on to conclude that the small scale hydro development in New Zealand is unlikely without government subsidies or further reforms to the electricity market and consent processes. While the location of DG in this case study has value to the network company through deferring investment and potentially improving line voltage, the benefits returned to the investor are not sufficient to compensate for the costs of the investment resulting in the project having very little value to the investor.

Consistent transmission, line and generation connection pricing methodologies across the industry would help.

Network Tasman has an open policy to DG, as it sees the need for it to shore up its network, but is concerned over the capital investments that are required to ensure the network can cope with the incoming DG. Due to its short-term outlook, which is caused by uncertainty in the growth patterns in the region, the ability to ride out developments without spending

	Revenue	Cost	Total
Capital/Investment		\$ 2,200,000	-\$ 2,200,000
Annual cost		\$ 72,000	
Annual income	\$ 216,000 (@ \approx 7 c/kWh)		
Rebates	\$ 4,000		
Net income			\$ 148,000
Pre tax payback			14.9 years

Table 5.13: Economics of the Onekaka mini hydro scheme

capital would be advantageous until a stronger idea of the needs of the region can be determined.

Case Study Discussion

General overview

For connection purposes (network management perspective) four distinct DG-categories can be distinguished:

- A. Residential generation, often solar PV-installations. These installations generally export little. Each installation per se has little influence on the network, but high density solar installations (future in urban areas) might create a combined impact on local feeders.
- B. (Co)-Generation that exports at times, e.g. cogen and landfill gas generators connected to an existing electric connection (industrial or landfill site)
- C. Generation only (or generation-mainly) DG like small hydro and wind sites in new connections. These are generally in more remote, rural locations with significant investments in project specific equipment (e.g. transformers, line to closest grid point, breakers, etc.) and relatively low connection density.
- D. Peak-logging equipment, often diesel gensets that have as a primary purpose providing backup services, but are also economically used to reduce the owner's peak demand charges and (sometimes) generate at lines company's signal to assist in system peaks.

These cases are summarised in Table 5.14. It is the export-only-category that most often impacts on lines' company costs, and is where DG-policy differences between lines companies seem to show the most influence.

Outline of DG-policies

In general all distribution lines companies appear to have a similar policy structure for DG, including:

- A published DG-connection process
- Cost pricing of project specific equipment
- Lines connection charges
- Transmission charges (connection &

interconnection)

- Rebates on lines charges and transmission charges for generation at peak times.

This seems a significant step forward to that previously and is in line with current government policy objectives.

However, government policy objectives with regard to pricing principles for DG have not been explicitly formulated and developed into a consistent industry approach to pricing methodology.

In principle all lines companies will charge project-specific equipment and related costs to the DG-developer. The DG-developer may choose to have equipment (esp. transformers) owned and maintained by the line company, but in many cases it is not specified how costs can be recuperated if other users make use of the same equipment in the future. This would seem a matter for further regulation and the issue is well recognised.

Treatment of annual lines connection charges seems to be the point of most difference. Powerco has a standard policy (for installations under 1 MW) that charges the same line use rates for Distributed Generators as for load, under the premise that they largely use the same common network (common costs). We note that Vector seems to adhere to the same principle, although this has not been specifically checked.

Orion indicates it will review connection charges on a case-by-case basis, reviewing the capacity on the local network. When sufficient capacity is available connection charges can be very small (a type of marginal cost pricing seems to be used; i.e. where no adaptations to the wider network need to be made for the DG-project, connection charges are small), although the number of cases implemented under this policy seem to be very limited. Network Tasman seems to adhere to similar principles, as their annual lines charges for the project reviewed are at a similar level.

Transmission (connection & interconnection) charges are charged in similar manners with slight variations in peak measurement methods, depending on the lines company characteristics.

	< 10 kW	< 1 MW	1 – 5 MW	> 5 MW
Non-export	Residential PV, SWH: Standard approach necessary, regulated?*	Negotiations with retailer and lines company of much lesser impact		
Export-import				
Export only	N/A	Most problematic little benefit/ incentive to lines company; high impact on viability. Too large for standard approach, too little for case-by-case Count number of renewable hydro-wind projects in this category	Potential problems (level playing field), but case-by-case approach warranted + negotiations possible	Case-by-case approach warranted + negotiations possible
Back-up and Peak lopping	N/A	Network and/or consumer orientated benefits		

* A "plug and play" approach appears to have the greatest potential in the domestic DG market, where product standardisation and mass production can deliver economic solutions. This can happen without significant change to LV distribution networks

Table 5.14: DG categories for connection purposes

All lines companies studied have a system for rebates where the DG-project supports the local network as well. For the Powerco-territory the rebates clearly depend on the zone (substation), whether any value is attributed to lowering system peaks. For the Orion territory generally urban peaks are in winter, and DG-installations that can generate in these peaks are attributed export (and/or generation) credits. Rural GXPs generally have their peaks in summer (irrigation related) and DG-installations in these areas are attributed export credits for generating in those peaks. Orion uses relay signals for announcing peaks. This contributes to predictability for DG-installations.

Implications of different DG-policies

The differences between the DG-policies reviewed become particularly significant for generation-only projects (especially small-scale hydro and wind)¹⁰. For peak-logging and co-gen installations, the DG-installations generally either lower the total peak (and therefore lines charges) or the generation peak is not significantly different from the (former) load peak (and lines charges remain similar under all

policies).

In the example of the diesel genset at Chateau on the Park it can be seen that the background and general pricing policies of Powerco and Orion networks are quite different. The Orion network operates quite closely to the security constraints of the transmission system and can be very constrained in (winter) peaks. Orion has consciously chosen to put more emphasis on peak charging (without a diesel genset the total lines charges for the hotel would seem to be almost 40% lower in the Powerco network than in the Orion-network). This gives considerable incentive to reduce peak demand.

Similarly Orion provides significant incentives to on-peak generation.

Powerco on the other hand has a network with significant spare capacity (except for specific areas like Coromandel). Their approach is more aimed at achieving revenues to pay for the capital costs of the network reinforcement in critical areas and thereby provides less incentive for peak reductions. In many areas they also provide rebates for generation coinciding with distribution and transmission system peaks, but since the system peaks are not very predictable (for the Distributed Generator), the risk of generating at high capacity outside the peak (and therefore being

¹⁰ Every generation project normally has some load for equipment, lighting, maintenance and start-up, when the generator itself is not generating. The peak load generally is significantly lower than the peak generation, though.

liable for a high connection charge) often outways the potential higher rebates. Investment would be covered if clear, predictable signals could be provided to align production to the system's peaks.

The DG literature shows that connection and pricing policy can be used to signal desirable locations and types of investment which in turn affects the actions of investors. Orion's policies reward system co-incident peak demand reduction whereas Powerco is focussed towards network reinforcement.

Case Study Evaluation

RMA-Consenting process and costs

Signals from several small-scale hydro-projects (including the 2 case studies included) are that the RMA-process for getting consent for installing the hydro-installation and using the water is lengthy, complex and costly given the scale of the projects. Apart from the up-front costs for acquiring the consents, several councils now pose annual charges for using the water (justified on the basis of monitoring and compliance costs) which can take up to 7% of gross annual revenue. This is a significant deterrent.

Consenting costs may very well make an otherwise viable project uneconomic. This is an issue for Regional Energy Strategies to identify opportunity and determine which ones are to be encouraged via appropriate provisions in Regional and District Plans.

Retail contracts

Generators are offered a variety of contracts by retailers that can reflect both local and system cost factors relative to their generation portfolio and customer base mix. Small independent generators with the hedging benefits of a retail customer base lack market power to realise full value recognition in energy purchase contracts.

The emergence of aggregators in the market confirms that there is an additional margin to be realised.

Small generators are in a stronger position if

they have storage, backup, and other diversified generation capacity.

Transmission Opportunities

DG has a sizeable opportunity with respect to avoiding transmission upgrades. However the current Grid Investment Test process that applies presents a bias towards transmission solutions to the detriment to DG solutions. We comment that that once a transmission solution has been approved there is no risk of the investment becoming stranded because of privileged pricing methodology. In the Orion circumstance, for example, a 10MW DG investment was not able to proceed through not being able to arrive at satisfactory contractual arrangements with the Electricity Commission. Instead, it should be possible to offer DG operators long-term contracts for transmission support that allow consistent risk treatments to be applied.

Economics

The cases studied – although few – confirm that it isn't easy to make an economic case for investment in DG in the present circumstances. Positive exceptions appear to be landfill gas and cogen projects, as well as peak-opping, especially if this generation is also necessary for reasons of security backup. Small projects based on hydro and wind resources seem particularly difficult when any distance from existing supporting infrastructure.

Particular difficulties encountered by new projects are: RMA-issues, access to affordable and experienced engineering, securing adequate retail contracts and negotiating line company connection contracts.

In general it can be concluded that Distributed Generation is an area that is new to many line companies and at present still a minor part of their operations. Treatment of connection charges can be significantly different between line companies, but a lot of learning-in-progress is taking place. This particularly impacts the generation-only and especially renewables (hydro and wind) DG-projects.

6 PROJECT FINDINGS & CONCLUSIONS

The analysis contained in this report was conducted with the intention of examining the feasibility of commercial DG in the current regulatory environment and to establish criteria to ensure successful DG investment. The desired high level overview of DG investment criteria and opportunities has not eventuated due to the recurring theme of the importance of location and other site-specific factors in evaluating DG investment opportunities.

The location of DG investment within a network is the most important factor in assessing the value of an investment to both the network company and investor. Every investment opportunity has unique effects on system performance, power flows, power quality, peak load reduction, protection systems and constraint management. To investigate the feasibility of DG investment each specific investment opportunity must be analysed individually to assess network impact, ability to defer investment and revenue/cost streams.

This type of study requires specialist knowledge of network characteristics at the proposed connection point, power flow studies, detailed costing of generation and connection technology, proposed generation levels and impacts of the investment on network operation. The individualised nature of DG means that developing generalised investment criteria is not appropriate to assess value and feasibility of investments. For example, in this study, the primary economic value creator ranged from transmission, distribution, energy market and consumer service applications.

The importance of location of DG investment and the unique characteristics of each investment is reflected in the connection and pricing policies of network companies. Policy development and implementation is used to encourage DG investment in locations where the greatest value to the network can be realised and to better achieve strategic objectives such as improving system security and power quality.

The importance of location to the value of DG

is illustrated by the case studies presented. Where the network realises very little value from the investment such as the Wanganui Valley hydro scheme and the Southbridge wind turbine, the value to the investor is also reduced as rebates from the network company are minimal. For investments that can be optimally located near to both network connections and fuel resources such as both landfill gas generation case studies the value to the investor is improved due to the onsite location of generation resources. The case studies presented illustrate that even within the same distribution network, DG investment value is unique to the proposed connection point and that a 'one size fits all approach' is not a sensible platform for DG investment assessment.

National policy, strategy and governance structures have only just reached a point where DG has a clear contribution to make and opportunity to participate. Government policy objectives with regard to pricing principles for DG have not been developed into a consistent industry approach to pricing methodology.

Some major worries have been expressed by all lines companies with regards to formalizing DG-policies at a national level:

- DG is often not as reliable and controllable for lines businesses, which limits their value in day-to-day operation of the lines business
- All lines businesses express reservations in signing long-term commitments in DG-connection contracts and rebate/credit prices in the light of changing Transpower pricing methodology and treatment on the Commerce Commission threshold regime which is due to be reset in 2009.

Additional concern has been expressed on coordination of legislation between the Electricity Commission and the MED. Coordination by one body would seem desirable.

Another issue with planning transmission upgrades is that New Zealand's transmission system was built for large grid connected

generation i.e. followed the decision to build generation. It is not located in areas where there are the most attractive DG resources (typically along the east coast). Small-scale developments can never support the cost of major line interconnection. The Grid Upgrade Plan process does not currently consider the strategic merits of building of transmission lines ahead of generation proposals to seed generation development. The Electricity Commission has a workstream “Facilitating Renewables” underway to address this issue.

With recent direction for renewables signalled by the New Zealand Energy Strategy more certainty exists with respect to the planning environment. Regions and communities now have a starting point for developing their own strategies, developing local resources for local benefit customised to local opportunities. This process should start with identification of opportunity and analysis of optimal solutions for local needs. It should necessarily have local political leadership, combined with business community and line company participation.

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ANNEX 1

*Aggregated Distributed Generation by region and
district for New Zealand*

National totals of DG by band and fuel type

This work was funded by NIWA under the EnergyScape Project

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		Band 1 (<10kW)				Band 2 (10kW to 1MW)				Band 3 (1MW to 5MW)				Band 4 (5 to 50 MW)				District Totals	District Totals	Total Regional	Total Regional
Geographic Region	District	Type 1 (kW)	Type 2 (kW)	Type 3 (kW)	Band 1 Total	Type 1 (kW)	Type 2 (kW)	Type 3 (kW)	Band 2 Total	Type 1 (kW)	Type 2 (kW)	Type 3 (kW)	Band 3 Total	Type 1 (kW)	Type 2 (kW)	Type 3 (kW)	Band 4 Total	(kW)	(MW)	(kW)	(MW)
Northland	Far North	0	0	0		0	0	0		0	0	0		0	0	25000		25000			
	Whangarei	0	0	0		0	0	0		0	0	0		0	0	0					
	Kaipara	0	0	0		0	0	0		0	0	0		0	0	0					
	Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	25000	25000			25000	25.00
Auckland	Waitakere	0	0	0		0	0	0		0	0	0		0	0	0					
	Manakau	0	0	0		0	0	0		0	0	0		0	0	0					
	North Shore City	0	0	0		0	0	0		0	0	0		0	0	0					
	Papakura	0	0	0		0	0	0		0	0	0		0	0	0					
	Auckland City	0	0.7	0		17141.8	0	0		22025	5400	7000		0	0	0		51567.5	51.57		
	Rodney	2	0	0		5824.5	0	0		4000	0	6000		0	0	0		15826.5	15.83		
Total	2	0.7	0	2.7	22966.3	0	0	22966.3	26025	5400	13000	44425	0	0	0	0	0			67394	67.39
Waikato	Thames/Coromandel	0	0	0		0	0	0		0	0	0		0	0	0					
	Hauraki	2	0.7	0		0	0	0		0	4900	0		0	0	0		4902.7	4.90		
	Franklin	0	0	0		0	820	0		0	0	0		0	0	0		820	0.82		
	Hamilton City	0	0	0		1800	1800	920		0	0	0		0	0	0		4520	4.52		
	Waipa	0	0	0		0	0	0		0	0	0		0	0	0					
	Matamata-Piako	0	0	0		0	0	0		0	0	0		0	0	0					
	Taupo	0	0	0		0	0	0		0	6000	0		0	0	50600		56600	56.60		
	Waitomo	0	0	0		70	0	0		0	3000	0		0	0	0		3070	3.07		
	South Waikato	0	0	0		0	0	0		0	0	7800		0	0	0		7800	7.80		
	Otorohanga	0	0	0		155	0	0		0	0	0		0	0	0		155	0.16		
	Waikato	0	0	0		1200	0	0		0	0	0		0	0	0		1200	1.20		
	Total	2	0.7	0	2.7	3225	2620	920	6765	0	13900	7800	21700	0	0	0	50600	50600			79067.7
Bay of Plenty	Whakatane	0	0	0		0	0	0		0	0	6360		0	0	35000		41360	41.36		
	Opotiki	0	0	0		0	0	0		0	0	0		0	0	0					
	Western Bay of Plenty	0	0	0		0	0	0		0	0	0		0	0	0					
	Kawerau	0	0	0		0	0	0		0	0	0		0	0	0					
	Rotorua	0	0	0		0	375	0		0	0	3500		0	0	0		3875	3.88		
	Tauranga	0	0	0		0	0	0		0	0	0		0	0	50500		50500	50.50		
Total	0	0	0	0	0	375	0	375	0	0	0	9860	9860	0	0	85500	85500			95735	95.74
Gisborne	Gisborne	0	0	0		0	0	0		4500	0	0		0	0	0		4500	4.50		
	Total	0	0	0	0	0	0	0	0	4500	0	0	4500	0	0	0	0			4500	4.50
Hawkes Bay	Napier	0	0	0		0	0	0		0	0	0		0	0	0					
	Hastings	0	0	0		0	0	0		0	0	0		0	0	0					
	Central Hawkes Bay	0	0	0		0	0	0		0	0	0		0	0	0					
	Wairoa	0	0	0		0	320	0		900	0	0		0	0	0		1220	1.22		
Total	0	0	0	0	0	320	0	320	900	0	0	900	0	0	0	0	0			1220	1.22
Taranaki	South Taranaki	0	0	0		340	0	400		0	0	1200		0	0	31400		33340	33.34		
	Stratford	0	0	0		0	0	0		0	0	1000		0	0	0		1000	1.00		
	New Plymouth	0	0	0		0	0	0		0	0	4500		0	0	0		4500	4.50		
Total	0	0	0	0	340	0	400	740	0	0	0	6700	6700	0	0	31400	31400			38840	38.84
Manawatu Wanganui	Ruapehu	0	0	0		340	3100	0		3000	0	0		0	0	0		6440	6.44		
	Rangitikei	0	0	0		100	200	0		0	0	0		0	0	0		300	0.30		
	Manawatu	0	0	0		0	0	0		0	0	0		0	0	0					
	Palmerston North	0	0	0		0	0	0		0	2500	1000		0	0	0		3500	3.50		
	Wanganui	0	0	0		0	0	0		0	0	4600		0	0	0		4600	4.60		
	Horowhenua	0	0	0		0	0	0		0	0	0		0	0	0					
	Tararua	0	0	0		0	0	0		0	0	0		0	68000	0	68000	68.00			
Total	0	0	0	0	440	3300	0	3740	3000	2500	5600	11100	0	68000	0	68000			82840	82.84	
Wellington	Wellington	0	0	0		10260	1750	0		4100	4000	2700		0	16000	0		38810	38.81		
	South Wairarapa	0	0	0		0	0	0		0	0	0		0	8850	0		8850	8.85		
	Masterton	0	0	0		0	0	0		0	0	0		0	0	0					
	Kapiti Coast	0	0	0		0	0	0		0	0	0		0	0	0					
	Carterton	0	0	0		900	0	0		0	0	0		0	0	0		900	0.90		
Total	0	0	0	0	11160	1750	0	12910	4100	4000	2700	10800	0	24850	0	24850			48560	48.56	
Marlborough	Marlborough	0	0	0		540	0	0		0	0	0		0	0	0					
	Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			0	0.00
Nelson	Nelson City	0	0	0		1230	0	0		0	0	0		0	0	0		1230	1.23		
	Total	0	0	0	0	1230	0	0	1230	0	0	0	0	0	0	0	0			1230	1.23
Tasman	Tasman	0	0	0		1020	1360	0		0	0	0		0	0	0		2380	2.38		
	Total	0	0	0	0	1020	1360	0	2380	0	0	0	0	0	0	0	0			2380	2.38
West Coast	Buller	0	0	0		0	0	0		0	0	0		0	0	0					
	Westland	0	0	0		0	662	0		0	4097	0		0	0	0		4759	4.76		
	Grey District	0	0	0		0	200	0		4050	0	0		0	0	0		4250	4.25		
Total	0	0	0	0	0	862	0	862	4050	4097	0	8147	0	0	0	0	0			9009	9.01
Canterbury	Kaikoura	0	0	0		0	0	0		0	0	0		0	0	0					
	Hurunui	0	0	0		0	0	0		0	0	0		0	0	0					
	Waimakariri	0	0	0		0	0	0		0	0	0		0	0	0					
	Christchurch City	0	0	0		9095.2	500	0		11288	0	0		0	0	0		20883.2	20.88		
	Selwyn	0	0	0		0															

